European Short-term Electricity Market Designs under High Penetration of Wind Power

European Short-term Electricity Market Designs under High Penetration of Wind Power

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Chapter 1

Introduction

This first chapter gives a general background of the thesis. Then, it introduces the research topic, defines the scope of the thesis and its objectives. It also gives a general overview of the chapters' contents that will be developed in the rest of the thesis.

1.1 Background

The increasing penetration of renewable energy sources for electricity (RES-E) in the European electricity system requires a significant effort to maintain the system balance at the lowest possible cost. The penetration of intermittent RES-E occurs in electricity markets which were initially designed for electricity systems with dispatchable generation. However, the variability and limited predictability of intermittent RES-E, together with an increase of network congestion, are posing major challenges to the operation and management of Europe's electricity system, which will only be aggravated with further integration of intermittent RES-E in the different electricity markets. In this respect, Glachant and Finon [7] argue that large-scale wind energy integration into electricity markets creates economic challenges on several fronts: market design and rules, support scheme design, strategic behavior in the presence of large-scale wind energy, and new methods for assessing the economic value of wind power.

An extended background of this thesis is provided in this section. It briefly explains the liberalization process in Europe, the role and structure of short-term markets, the integration of national electricity markets in Europe and the increase of renewable sources in Europe.

1.1.1 Electricity liberalization process in Europe

Electricity, as a commodity, has special characteristics that make it different from others. First, it is currently expensive to store electricity in big quantities; therefore, generation and load need to be matched continuously. Second, electricity systems need physical infrastructure to connect and match supply and demand. The physical infrastructure is complex and has different components such as the grid, transformers, protection devices, etc. Third, electricity systems are interconnected across national borders and electricity flows follow physical rules, such as Kirchhoff's laws, instead of pathways defined by contracts. These characteristics make electricity system operation a difficult task.

Electricity systems, in Europe and around the world, used to be considered natural monopolies. In most countries, a single national company was in charge of the system operation, owned all the physical assets (generation units and grid components), and delivered electricity to final consumers. However, since the 1990's, the electricity systems in the EU have been transformed from national monopolies into a liberalized environment, where power generation and the supply of energy services are taking place in competitive markets, and the reforms are still ongoing[1].

In the current liberalized context, the economic dimension of electricity systems has been organized into different markets, catering for long-term and short-term arrangements over a range of time constants. The design and organization of these markets define the responsibilities of the different actors and delimit their actions. One of the main actors is the System Operator (SO)[2], who is in charge of the system balance, security and reliability. The SOs usually buy system services from market parties (from both supply and demand sides) and take actions in real time to achieve their objectives. On the other hand, market parties, such as generators, suppliers and traders, buy and sell electricity in the different markets and are constrained by market rules and network codes.

1.1.2 European short-term electricity markets

The focus of this thesis is on the short-term market mechanisms. The short-term mechanisms considered in this thesis are defined as those that take place from the day-ahead until delivery hour, i.e. the day-ahead and intraday markets, and actions that are necessary for system balancing and congestion management. Figure 1.1.1 shows a simplified representation of the timing of short-term markets. In general terms, short-term European electricity markets are organized in a time sequence of markets, where the day ahead market plays an important role in terms of trading

[1] Liberalization has been enforced starting with the Electricity Directive 96/92/EC, and followed by the second and a third directives: 2003/54/EC and 2009/72/EC, respectively. This process is still under development with new regulations.

[2] Transmission System Operators (TSOs) if SOs own also the transmission grid.

volumes. These European day-ahead markets have a single national price[3]. The intraday markets, which take place after the day-ahead market, give the possibility to update the energy schedules. In Europe, the energy markets, such as the day-ahead and intraday markets, are managed by the market operators, which do not consider network or security constraints. SOs carry out these latter tasks. Because of limited storability, the physical trade of electricity only takes place in real-time, which is thus the only true "spot market" [8]. MacDonald [8] argues that other markets are all "forward markets" that trade derivatives products maturing in real-time on the spot market. This makes the economic signal conveyed by the Balancing Market all the more important, as the real-time or imbalance prices expected to be brought forth by this market are reflected in wholesale prices and consequently affect market parties' decisions at the forward stage.

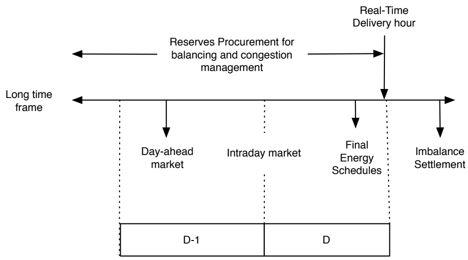


Figure 1.1.1: Timing of short-term European electricity markets

After the day-ahead market (and in some cases the intraday markets), and considering bilateral trading, SOs use congestion management mechanisms to solve foreseen congestions. Congestion management is usually based on redispatching of generating units, so that, the results from day-ahead and intraday markets are made technically feasible in the physical system.

In the electricity system, the active power balance has to be maintained each instant, as disturbances in the power balance cause the system frequency to be disturbed. SOs use different balancing services to maintain the system frequency target value and avoid overload of transmission lines. In balancing markets, SOs trade the remaining imbalances, as they hold the responsibility for system security. Additionally, SOs obtain (through purchasing or regulation) system services such as compensation of network losses and voltage control, collectively called ancillary services. However, these last two services are not analyzed in this thesis.

In Europe, balancing services are bought independently from the day-ahead and intraday markets (self-dispatch). This aspect can potentially cause inefficiencies in sequential markets as they do not incorporate joint restrictions of power plants (some

[3] In some markets, such as the Nordic region and Italy, zonal pricing has been implemented, which implies that these countries are divided in different predefined zones depending on the occurrence of congestions.

existing of these inefficiencies have been illustrated for the Spanish case in Section 2.3). Borggrefe and Neuhoff [9] claim that a joint provision of energy and balancing services efficiently incorporates the inter-temporal constraints of power plants. This is particularly important for systems with dominantly thermal units, with ramping limitations or significant start-up or shutdown costs. The joint optimization of energy and balancing services is applied in some USA markets, such as PJM. Although this joint optimization of energy and balancing services can potentially improve system efficiency, this arrangement is out of the scope of this thesis, as it would require drastic change in the current European market design.

Balancing services can be divided into different types, classes and direction [10]. This classification is represented in Figure 1.1.2. Direction refers to upward and downward regulation, where the first one refers to a increase in generation (or decrease in consumption) and the last one refers to a decrease in generation (or increase in consumption). Upward regulation is usually provided with units that are more expensive than the marginal unit of the day-ahead/intraday market (at higher prices than the day-ahead price), whereas for downward regulation those units that already received payments from the day-ahead/intraday market can save the fuel costs by decreasing generation. Part of this money is paid back to the SO, unless there is a cost for decreasing generation and the SO pays the market party. Further description of the balancing mechanisms is provided later in this thesis.

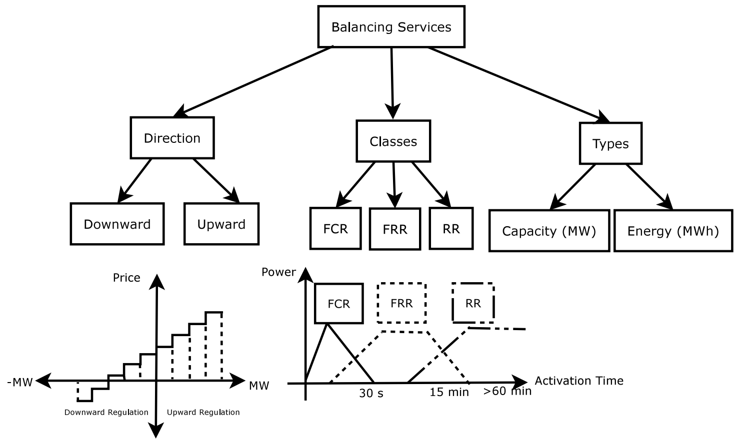


Figure 1.1.2: Balancing services classification

System Operators use different balancing services to keep the system frequency target value within certain limits. In general terms, in Europe, active power balancing services (reserves) can be divided in three classes [11]: Frequency Containment Reserves (FCR), Frequency Restoration Reserves (FRR) and Replacement Reserves (RR). These reserves are differentiated by activation time, activation mode and their functionalities. Although there are differences between countries and especially between different ENTSO-E Regional Groups, reserves can be defined as follows. FCR stabilize the system frequency in a time frame of seconds (usually up to 30 seconds) with automatic and local activation. FRR restore system frequency to its set point (50 Hz). FRR also restore the balance between generation and demand for each SO control area, and the power exchanges between SOs balancing areas to their set points. FRR typically have an activation time up to 15 minutes. FRR can be activated automatically or manually. SOs use RR to replace further imbalances if FCR and FRR have been activated or when market participants cannot compensate themselves for their imbalances. Generally, the activation time of RR ranges from 15 minutes up to hours.

Those balancing services (FCR, FRR and RR) can be purchased for both capacity (MW) which refers to service availability, as well as energy (MWh), which refers to final use and activation of these services.

Market parties participate in different markets and react to the economic incentives in place. In a liberalized context, the objective of market parties is to maximize their profit by trading in different markets. This participation is complex and depends on many different variables of market design and regulation. Part of the tasks of regulators and governments is to align market incentives with social welfare optimization.

1.1.3 European electricity market integration

The main European institutions that regulate the electricity sector have been working to achieve an Internal Electricity Market (IEM), starting with the implementation of Directive 2003/54/EC and pushed by the European Commission to be completed by 2014 [12][4]. Because of the IEM, integration and harmonization of different markets and the operation of national systems are taking place within Europe. The IEM process is ruled by Network Codes and Framework Guidelines developed by ENTSO-E (European Network of Transmission System Operators for Electricity) and ACER (Agency for the Cooperation of Energy Regulators), respectively. This harmonization has been embedded in different market mechanisms, including the day-ahead market coupling and the intraday implicit allocation of transmission capacity [14, 15]. One of the main difficulties to achieve an implicit allocation of cross-border capacity is the coexistence of different market designs between different regions. For the intraday market, for example, discrete auctions and continuous trading coexist, making it unlikely that the 2014 IEM goal will be achieved.

Furthermore, for the next steps of this EU wide harmonization process, European institutions have considered integration of balancing markets and procurement of balancing services [16, 5]. However, at this moment European countries still differ widely in regulations and market designs. There is currently little integration of balancing mechanisms, which have been usually designed within national borders. Additionally, security constraint mechanisms usually do not consider data and

[4] However, the European Commission has expressed concerns that the EU might not be on track to meet the 2014 deadline [13].

impact on neighboring countries. This lack of coordination and harmonization of short-term market mechanisms can imply losses in terms of economic efficiency and can present market parties with arbitrage opportunities that might endanger system balance and security.

1.1.4 Increase of wind power in Europe

The European Commission′ s Directive 2009/28/EC established a mandatory national target of a 20% share of RES-E in final energy consumption. This legislation has already caused a significant penetration of wind power. For example, from 2000 to 2012, 27.7% of new capacity installed has been wind power [17][5]. A substantial increase of wind power in the overall generation portfolio requires more effort to balance the electricity systems due to the variability and limited predictability of wind power. In addition, most wind power installations are located in remote, especially offshore areas far from load centers, which is likely to increase grid congestions.

Wind power is capital intensive, with high investment costs and almost zero variable costs. In Europe, however, wind power has currently an opportunity cost which is reflected by the support schemes. This opportunity cost is relevant for the participation of wind power in different markets. Furthermore, wind power should be incentivized to improve energy forecasts and reveal this information in the markets. As shown in Figure1.1.3, wind power forecast errors significantly decrease from the day-ahead closer to real-time. In addition, as there is no unique methodology to compute energy forecasts, bidding strategies can be based on profit maximization strategies and risk preferences, which can lead to a mismatch between the energy forecast and the actual energy bid. From the SO perspective, this is challenging as energy forecasts become more uncertain, not only because of forecast errors but also because of strategic bidding behavior.

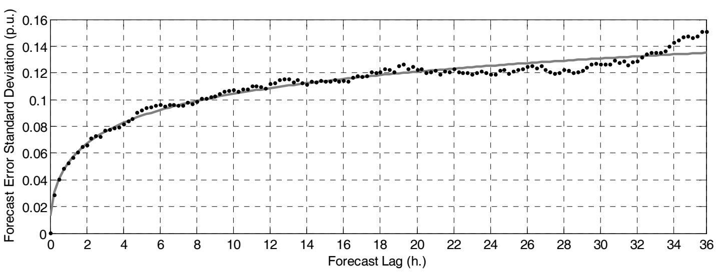


Figure 1.1.3: Normalized standard deviation of wind power forecast error for 12 GW of installed capacity versus forecast horizon[1]

[5]Wind power already represents a significant share of total electricity generation. The countries that have a higher share are: Denmark (27%), Portugal (17%), Spain (15%), Ireland (13%) and Germany with 11% [17].

1.2 Research topic: electricity market designs under high wind power penetration

With an increasing share of wind power, market designs in Europe should be adapted to new flexibility requirements. This adaptation is necessary because of the characteristics of wind power (variability and limited predictability). Aside of these characteristics, wind power has been treated differently in some markets and specific market rules have been applied to this technology, for example with respect to the participation of wind power producers in electricity markets and in the system balancing. Hence, new challenges have emerged from the specific characteristics of wind power and its interactions with the markets. Consequently, a detailed analysis is required to determine if wind power needs such a special treatment and how wind power producers participate in electricity markets with different rules and market designs.

The way wind power producers (and power producers from other intermittent RES) participate in short-term markets differs from conventional power sources. For example, SOs do not have a unique way to verify the wind energy forecasts as forecasting methodologies are diverse and involve many uncertainties. If market rules related to intermittent RES-E are not properly defined, market parties might profit from those flaws and possibly manipulate markets. New possibilities of market manipulation must obviously be avoided and should be studied in detail.

All these discussed challenges increase in the context of market integration, where differences in national market designs could create additional inefficiencies, increase integration costs or cause cross-subsidies between countries and market parties.

Some literature has pointed out the need for change in short-term market designs under high wind penetration, such as Katholieke Universiteit Leuven and Tractebel Engineering [18], Weber [19], Ela et al. [20], Vandezande et al. [21], Henriot and Glachant [22]. In addition, strong interactions between different short-term markets have to be considered, as stated in Just and Weber [23], Benedicto Martínez [24]. There are still open questions about the successful participation of wind power in short-term electricity markets. This is an active research field and its relevance will increase in the coming years and decades.

Figure 1.2.1 represents the main market mechanisms considered in this thesis regarding the interference of wind power with these mechanisms. The participation of wind power in different short-term markets and mechanisms is important because forecast errors decrease closer to real time. The following subsections describe the main challenges associated with the design of short-term markets and the participation of wind power producers in these markets. These challenges will be covered in this thesis.

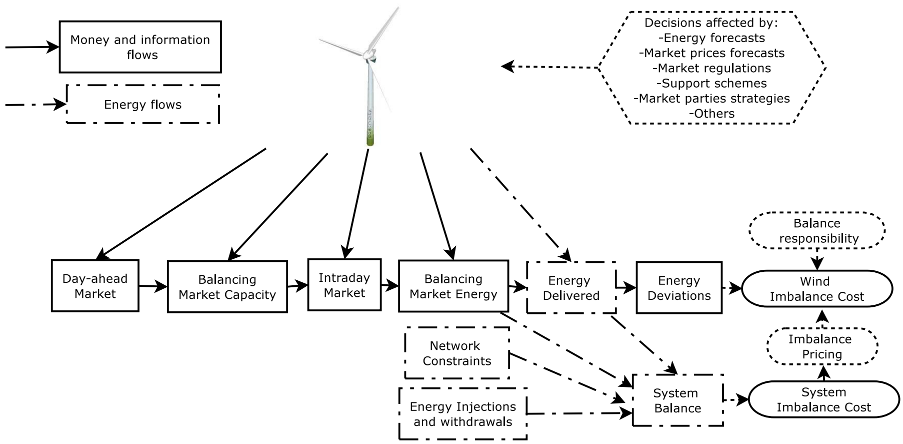


Figure 1.2.1: Research topic diagram

1.2.1 Support schemes for wind power

In general terms, renewable energy units need some support from governments to be profitable, at least in the short-term. In Europe, these subsidies differ among countries, not just by the amount of the subsidy but also by the mechanisms and responsibilities for market parties. These support schemes determine the opportunity costs of generating electricity from wind power. The opportunity cost is important for the system operation as it determines the cost of using wind power for system balancing purposes.

Wind power has an important effect on market prices. It affects, for example, the merit order [25], and it may occasionally decrease prices to zero or even cause negative prices. When negative electricity prices are allowed in markets and wind power participates in these markets, support schemes represent the price floor (with negative sign) that units are willing to bid in the market. However, negative prices are not allowed in all European countries, which leads to national market conditions.

The design of support schemes can significantly influence incentives for wind power producers to participate in different markets. For example, a fixed feed-in tariff (FiT) without balance responsibility, might not incentivize to improve energy forecasts or trade in markets. But the allocation of balance responsibility to intermittent RES-E per se may not always minimize balancing costs, especially in the presence of markets distortion, which can give perverse incentives to market parties (as further described in Chapter 2 and Chapter 7).

1.2.2 Wind power and intraday markets

The design of intraday markets increases in relevance with the increase of wind power penetration in the generation portfolio. Wind energy forecast errors decrease significantly at hours close to real time, for example, from 36 to 3 hours before delivery, the forecast error can decrease by almost 50% [26]. Intraday markets allow balancing by market parties before SOs take actions to solve remaining imbalances. For wind power producers, the intraday market is crucial to correct forecast errors and avoid imbalance penalties.

Bidding behavior in the intraday market also depends on other trading possibilities, as wind power producers have the option to participate in different markets (day-ahead, intraday, balancing markets), and take decisions about energy delivery to maximize their income considering intraday energy forecasts.

Currently there are two main designs of balancing markets in Europe: continuous trading and discrete auctions. Both designs have pros and cons, as revealed by the experiences of different countries that have implemented either one of them. Between these two options, there is a debate about which is the best option for integration of wind power and which market design permits more liquidity. In addition, there are important challenges for the integration of intraday markets between countries and regions, for instance to determine cross-border arrangements between countries with different designs [27], and transmission capacity pricing under continuous trading schemes [28].

1.2.3 Wind power and balancing arrangements

Balancing arrangements can be decomposed into three main pillars [29]: balance responsibility, balancing service provision and imbalance settlement. The balance responsibility defines the obligation of market participants (generators, suppliers and traders) to submit schedules (for both consumption and production) to the SO, and the financial consequences of responsibility for deviations from those schedules. Market participants, in this sense, are called Balance Responsible Parties (BRPs).

The balancing service provision defines how different balancing services (i.e. ancillary services for frequency control) are bought and how providers of balancing services are remunerated. SOs usually buy the balancing services in the balancing markets (which can have capacity and energy components); participants in those markets are called Balancing Service Providers (BSPs).

The third pillar of balancing arrangements refers to how imbalances and imbalance prices are determined, and thereby how balancing costs are allocated to BRPs. BRPs are incentivized to submit accurate schedules, because they have to pay imbalance prices for deviations (under certain imbalance pricing regimes it can be profitable for market parties to deviate from their energy schedules).

The classification of balancing mechanisms proposed by van der Veen and Hakvoort [29] is adopted to pursue the analysis of balancing markets in relation with wind power. The different balancing arrangements affect the profitability of wind power and the operational costs of managing the system. It has been discussed that the increasing share of intermittent RES-E in Europe requires an increasing need of balancing services [30, 31]. However, from a technical point of view, wind power itself can contribute to the provision of balancing services [32]. The challenge is how to design balancing mechanisms to successfully include intermittent RES-E, such as wind power, in the provision of these services.

1.2.3.1 Wind power as a Balance Responsible Party

Wind power producers may have different levels of financial responsibility for energy imbalances in relation to other technologies. For instance, there are countries where wind power has been exempted from balance responsibility (Germany until 2011), countries with tolerance margins (Belgium), with imbalance subsidy (Denmark) or full balance responsibility (the Netherlands, Spain, Sweden). These different economic regimes give different incentives to bid in the markets and have different impacts on the system.

1.2.3.2 Wind power as a Balancing Service Provider

Under certain conditions, the provision of balancing services by wind power can be cheaper than using other power sources, even when considering the opportunity cost (reflected by the support schemes). For instance, a decrease of wind power producers can be justified in hours of high wind power generation and low demand, and when thermal units face high costs for reducing their output or for ramping. In addition, wind power can update wind energy forecasts in balancing markets to decrease the need for balancing services.

1.2.4 Wind power and congestion management mechanisms

Wind power can increase grid congestion, as wind farms are usually located far from demand locations. Under high wind generation, it might be needed to curtail wind power for congestion relief purposes. Deep connection charges, where a new installation pays the entire network cost (including grid reinforcements) caused by its connection to the system, can potentially decrease network congestion and provide long-term locational signals. On the other extreme, shallow charges (where the new connected installation only pays the cost of its own connection to the system, without considering additional impacts on the grid) do not provide full locational signals [33]. This thesis does not further discuss the role of connection charges, as they are long-term aspects, but they are important design variables for the integration of RES-E. On the other hand, locational signals in the energy market are crucial to ensure short-term efficiency. In this respect, different authors advocate a change in the European pricing mechanisms to nodal pricing [34, 22]. Further discussion on locational price signals can be found in Chapter 5.

The increase of network congestion within countries might require a redesign of balancing mechanism, such as imbalance pricing. To solve network congestions local resources need to be activated, but most of the European imbalance pricing mechanisms are computed at the national system level, which can create adverse price signals for players in congested zones to affect the local energy imbalances. The consideration of grid congestion is analyzed in more detail in relation to the imbalance pricing mechanism in Chapter 5.

1.2.5 European priority dispatch for renewable sources

The so-called "priority of dispatch" rule included in the EU legislation (under Directive 2009/28/EC), implies that RES-E based generation can be only curtailed because of system security reasons, even if a unit commitment algorithm indicates that it is more economically efficient to curtail wind power or other RES-E [25]. The rationale of this rule is to accomplish RES-E targets and to incentivize more flexible generation. The downside of this rule is that it may cause inefficient dispatch of power plants. The alternative of putting RES-E in the market increases the investment risk and the long-term commitment of RES-E.

The effect of this priority rule should be studied in more detail, comparing both short-term with long-term efficiency to fulfill the renewable targets. However, the European Commission [35] apparently decided to focus on short-term efficiency gains and argues that, as markets evolve and grid operations become more neutral as a result of unbundling of the electricity value chain, the priority dispatch rule will in time become obsolete. The elimination of this rule for existing units can be conflictive, as priority dispatch has already been granted. Additionally, in case that priority dispatch is not longer available for new installations, these installations will face higher risks of curtailment. For new installations, possible curtailment compensation mechanisms will play an important role.

1.2.6 Cross-border balancing arrangements for wind power integration

Differences in balancing mechanisms between national systems may create inefficient cross-border electricity trade due to the lack of harmonization. European institutions are currently designing general guidelines for the development of a Network Code on Electricity Balancing, but those guidelines still give a certain amount of freedom to national authorities to design their own balancing mechanisms and regulations. This heterogeneity in designs may cause losses in economic efficiency as prices and costs are distributed unequally between countries. Janssen [36] provides a comprehensive analysis for the coordination and harmonization of cross-border electricity trade in Europe from long-term to short-term markets. The author highlights the main trade-offs at different integration levels in terms of efficiency gains and implementation requirements. This thesis focuses on the harmonization challenges for short-term markets, without entering into details of implementation or institutional analysis, which are presented in Janssen [36].

1.3 Research scope

Electricity systems are characterized as complex socio-technical systems, in which a complex market system interacts with a complex physical system. The behavior of a complex socio-technical system is the result of decisions made by many different agents with different interests guiding their operational and investment behavior. To ensure that the overall system produces socially desirable outcomes, markets must be carefully designed, including the allocation of rights and responsibilities to the different agents. Meanwhile, the system is in a state of constant flux, as the EU aspires to transform the electricity system from a system predominantly based on fossil fuel sources[6] to an almost fully decarbonized system. This process is known as energy transition [37]. In the context of energy transition, the short-term electricity markets play an important role in ensuring economic efficiency, and therewith affordability of energy services, in the decarbonized electricity system of the future.

This research is embedded in the area of Energy Economics and Energy Policy. This thesis is mainly focused on short-term electricity markets and specific regulations related to the increasing penetration of intermittent RES-E, mainly wind power. In this context, existing market design flaws become more significant than they were before, as the integration of wind and other intermittent RES-E requires more flexibility and well-functioning of short-term markets.

The scope of this thesis includes mainly two groups of problem owners: wind power producers and policy makers. Policy makers are those that have the right to change market rules, such as national electricity regulators, SOs and governments. Both national and European policy makers are considered in this thesis. Market designs affect, on the one hand, the system costs and operation and, on the other hand, the economic profits of wind power producers. Wind power producers are analyzed from both perspectives: as Balance Responsible Parties and Balancing Service Providers, as well as a mix of both roles in electricity markets.

The geographical scope of this thesis is the EU context. Some specific case studies are interesting as some countries currently have very high wind penetration, such

[6]Except for those countries with abundant hydro or nuclear power.

as Denmark, Spain and Germany. However, these countries are part of Regional Markets such as the Nordic, Iberian and Central West European markets. Simultaneously, the integration of these regional markets is taking place in Europe to achieve the Internal European Market.

In European electricity markets, short-term markets and regulations differ among countries. Those differences can create trade incompatibilities, inefficiencies and therefore increase the costs for electricity users. Harmonization of rules and multinational cooperation can lead to important benefits like the improvement of system security, efficiency in the use of balancing resources and transmission capacity, and increase of capabilities for integration of renewable sources. Consequently, this research will evaluate current national designs and alternative designs that can improve the integration of wind power in electricity markets, and at the same time, improve economic efficiency.

This thesis studies the interrelations between the various short-term markets such as day-ahead, intraday and balancing markets, as well as congestion management, and cross-border issues. Economic, institutional and technical aspects of electricity systems will be taken into account when evaluating different market designs.

1.4 Research relevance

The results from this research are expected to have academic and practical relevance. From an academic perspective, it will contribute to a deeper understanding of the interrelations between different short-term market mechanisms and balancing arrangements, and the interference of wind power with these short-term markets and balancing arrangements. The particular interference of wind power in the short-term market has not been yet discussed in the literature and this thesis is expected to bridge this gap.

This thesis has practical relevance for policy makers and market parties. Some of its expected contributions to national and European policy making are the identification of good practices for operational management of electricity systems, and evaluation of the social costs of different balancing designs. Also, it is in the interest of policy makers to understand the potential impacts (costs and benefits) of a lack of international harmonization and cooperation on the integration of wind power in short-term electricity markets. This thesis aims to provide an assessment of alternative designs and regulations.

This thesis is also expected to be relevant for market parties such as wind power producers, intermediaries, and traders. This thesis provides a clear overview of the interactions between wind power producers and short-term market arrangements in order to build up strategies to maximize their profits. Bidding models are developed to compute the impact of cross-border electricity trade on these markets and test the impact of different market rules. In addition, this thesis uses a system model to compute the impact of some market rules on the system costs and finally on consumers.

1.5 Research questions

The main research question of this thesis is:

Given the increasing share of wind power in the European electricity system, to what extent can short-term electricity market designs improve economic efficiency without endangering the system security?

Some specific sub-questions are:

1. How are short-term markets in Europe designed and how are they interrelated?
2. How can intraday markets be designed to allow balancing of intermittent RES-E, such as wind power, and how can the liquidity of these markets be improved?
3. For different balancing designs, what is the relationship between public and private costs of wind power producers' balancing strategies?
4. What are the design choices for allocation of balance responsibility for wind power and how can they be assessed?
5. Based on different market designs, which balancing strategies exist for wind power producers to reduce imbalance costs?
6. What are the implications of a lack of harmonization of short-term market designs and regulations in Europe?

1.6 Methodology

For the evaluation of different market designs, different methodologies are used depending on the specific aspect of interest. A stochastic optimization is used to compute bidding strategies of wind power producers in different short-term electricity markets. For this purpose, forecasting techniques are used to consider both uncertainties of wind energy forecasts and different electricity prices. These forecasting techniques have been used to compute price uncertainties in different time frames. Based on forecasting models, Monte Carlo simulations are performed. This methodology has been used in Chapters 3 and 7. The modeling of bidding strategies is based on existing literature, as explained in detail in the respective chapters. In this thesis, the bidding models are further developed and adapted to the case studies and the corresponding regulations. Furthermore, the results clarify the role of different market designs that to our knowledge were not studied before.

Econometrics and statistical techniques are used to compute interrelations between relevant variables and test the statistical significance of the models results. These techniques are mainly used in Chapter 2.

An operational model developed by Comillas University (ROM model) has been used to assess the impact of proposed changes in the priority dispatch rule for renewable energy sources. This model has been further developed to differentiate between renewable sources and to measure distributional effects among market parties as a result of the proposed changes. This model has been used in Chapter 6.

The analysis of market data is used to study the markets evolution in terms of prices and market parties' behavior in different short-term markets, which were not analyzed previously by the existing literature.

An agent-based model has been used to measure the effect of different national imbalance pricing rules on cross-border electricity trade. This model is described in Chapter 8.

1.7 Thesis outline

This section gives a brief description of the contents of the remaining chapters.

Chapter 2 Managing imbalances of intermittent RES-E: the role of intraday markets

With a high penetration of intermittent RES-E, the intraday market is expected to increase in relevance to allow intermittent RES-E to correct for forecast errors and to minimize the need for action by SOs to solve remaining imbalances. Currently there are two main intraday market designs in Europe: continuous trading and discrete auctions. There are theoretical and empirical discussions of the benefits of each design. The analysis presented in this chapter provides new insights in comparison with the existing literature about the European intraday markets from both empirical and theoretical point of view.

In order to evaluate both options, first the Spanish intraday market is described, which is based on discrete auctions. This is an interesting case study because the Spanish intraday market is the most liquid in Europe. Additionally, this market has been pointed out in the literature [19, 9] as a good design for the integration of

RES-E. However, the literature has not analyzed in detail why the Spanish intraday market has such a high liquidity and if indeed this market has helped to integrate wind power in the system. These questions are answered based on market data and the description of related market rules. Second, the German intraday market based on continuous trading scheme is studied using bids data provided by the German power exchange (EPEX). In addition, the balancing actions used by the German TSOs to manage RES-E caused imbalances are studied based on TSOs' available data.

Intraday markets usually have a low liquidity; therefore, it is necessary to adapt market regulations in such a way participation in these markets is increased. One possibility to increase liquidity is the introduction of financial arbitraging (known as convergence bidding) between day-ahead and intraday markets, which can improve efficiency in European intraday markets. This market policy has been successfully implemented in US markets for more than ten years with positive results in terms of market liquidity and economic efficiency. This thesis explores if convergence bidding can be an attractive policy for the Spanish and German markets.

Finally, the current state of intraday markets in Europe and challenges for integration of these markets are presented.

Chapter 3 The impact of cross-border intraday markets in wind power balancing strategies

Depending on the allocation of balance responsibility to wind power producers, they are more or less incentivized to reduce imbalance costs. The strategies of wind power producers in short-term markets to reduce imbalance costs are examined. Chapter 3 describes the balancing rules applied in the Netherlands and analyzes bidding strategies in day-ahead and intraday markets, and wind power producers' decisions on final energy delivery. A stochastic optimization model represents the intraday trading possibilities between Germany and the Netherlands, which can potentially decrease imbalance costs for Dutch wind power producers. Uncertainties about prices, energy forecasts and interconnection capacity in the day-ahead and intraday time frames are included in this analysis. This analysis is novel in the sense that it includes cross-border aspects of intraday markets and adds to the existing literature on bidding strategies new insights into the influence of different imbalance pricing mechanisms.

Chapter 4 Participation of wind power in balancing mechanisms

The participation of wind power has been restricted to some electricity markets. For instance, wind power cannot participate directly in most European markets for balancing or congestion management, except for the Danish case. However, ACER [5] requires that the Network Codes shall set terms and conditions to allow load and intermittent RES-E to participate in the provision of balancing services. There are potential benefits from the participation of intermittent RES-E in balancing markets in terms of gains in economic efficiency and security of the systems. However, market rules need to be adapted to avoid possible risks of this participation. This chapter highlights some of the main challenges for the participation of wind power in the balancing mechanisms.

Chapter 5 The interplay between balancing arrangements and network congestions

Chapter 5 describes the interplay between internal congestions (in the national grid) and imbalance pricing mechanisms. Because of internal congestions, imbalance prices can incentivize market parties to create intentional imbalances, which can endanger system balance and security. This chapter focuses on the German market and gives some evidence of gaming possibilities for market parties, as a result of national imbalance pricing design and the existence of internal congestions. Finally, this chapter proposes alternatives designs for imbalance pricing, which can provide robust price signals even in the context of internal congestions. The interplay presented in this chapter has not been addressed in the existing literature.

Chapter 6 Proposed changes in the European priority dispatch: the Spanish case

Different market rules affect intermittent RES-E curtailment. This chapter models the elimination of the zero price floor in the Spanish market, together with the elimination of the priority dispatch rule for RES-E. The model measures the changes in system costs and distributional effects on market parties, mainly with respect to the costs faced by consumers and the revenues of intermittent RES-E. Based on the model results, the need for curtailment compensation is measured to compensate for curtailment risk. The existing literature has neither explored the effect of the priority dispatch rule on the systems operational costs nor the implications of the distributional effects for different market parties.

Chapter 7 The impact of European balancing rules on bidding strategies for wind power producers

Chapter 7 discusses the financial implications of different balance responsibility rules and imbalance pricing on wind power producers' profitability. This chapter analyzes balancing regulations of four European countries: Belgium, Denmark, Germany and the Netherlands. A stochastic optimization model is adapted to the countries' balancing rules to measure the impact of imbalance pricing and the allocation of balance responsibility on the profitability of wind power producers. On the basis of the model outcomes, chapter 7 proposes changes in current balancing rules applied to wind power to improve the incentives for wind power producers to reduce imbalance costs and avoid distortions in the markets. This chapter contributes to the literature with an evaluation of the impact of the balancing rules on the bidding strategies and costs for wind power producers and potentially for the systems.

Chapter 8 Effects of lack of harmonization of balancing arrangements

This chapter studies how different short-term market designs can affect the economic efficiency of electricity markets in Europe. On the one hand, cross-border intraday trading and gate closure times closer to real time have been promoted [38]; but on the other hand, imbalance pricing rules remain within the national scope. This can generate incentives for market parties to arbitrate between short-term markets, resulting from different market designs. This chapter discusses the main differences between North European countries, as there are initiatives for countries of this area to substantially increase offshore wind development and interconnect offshore wind parks with meshed grids [39]. This chapter presents the implication of having different balancing rules among neighboring countries and relates them with the current European proposals in these aspects. To the author's knowledge, the analyzed aspects have not before been analyzed in the literature.

Chapter 9 Conclusions and recommendations

The main conclusions of this thesis are presented in this chapter. From the analyses carried out in this thesis, different recommendations are extracted for European policy makers and discussed. Finally, suggestions for further research are provided.

Chapter 2

The role of European intraday markets to manage energy imbalances

2.1 Introduction

Intraday markets play an important role in allowing intermittent generation to update energy forecasts and trade closer to delivery time. Currently in Europe there are two main designs of intraday markets: discrete auctions and continuous trading. The Iberian and Italian markets have discrete auctions, while the rest of the European countries have continuous trading. Further description of the characteristics of these markets is described in Section 2.2.

This chapter analyzes both intraday market designs, with special analysis of the Spanish and German markets. It also highlights the main differences in the designs in relation to the balancing of intermittent generation. The Spanish and German markets are interesting case studies as they present the two European intraday designs; and additionally, these countries have high share of intermittent RES-E. Furthermore, this chapter discusses the current design challenges for the European cross-border intraday markets and provides a general discussion on the design aspects that should be considered for the European implementation.

The Spanish intraday market has been usually pointed out as a good design in terms of market liquidity in comparison with other European intraday markets [19, 9]. One of the main reasons given for this high liquidity is the discrete auction design. However, besides the market design, different market rules of the Spanish market can encourage market parties to trade in the intraday market, for example the allocation of balance responsibility to RES-E, the imbalance settlement, or the interrelation with other short-term markets mechanisms as explained in Section 2.3.

Section 2.4 describes the behavior of the German intraday market, which substantially differs with the Spanish market. In addition, changes in the German support schemes varied the use of balancing services by the TSOs.

Finally, Section 2.5 proposes the implementation of financial arbitraging (known as convergence bidding) in the German and Spanish markets. The attractiveness for the implementation of convergence bidding in these two markets is explored by analyzing the forward risk premium between day-ahead and intraday prices. Then, the potential benefits of the implementation of this policy in these markets and possible implementation in the European context are discussed. The Spanish and the German intraday markets have higher trading volumes in comparison to other European intraday markets [40]. Therefore, the application of convergence bidding can be even more attractive to other markets.

2.2 Description of existing European market designs

In Europe there are currently two main designs for the intraday market: discrete auctions and continuous trading. The main characteristics of both designs are shown in Table 2.1. In a discrete auction design, the market has different sessions at specific time. The market-clearing algorithm in a discrete auction (as in the Iberian market) is based on a marginal pricing rule with uniform prices. This means that bids are stored and ordered in a merit order until the gate closure time. The market price is determined by the intersection of demand and supply curves.

Table 2.1: Characteristics of European intraday markets

Market characteristics	**Continuous trading**	**Discrete auctions**
Pricing mechanism	Pay-as-bid/Average pricing	Marginal pricing
Matching time	Continuously/First-come-first-served	Predefined gate-closure times
Times that same product can be traded	Not limited within the trading period	Fixed
Cross-border capacity allocation	Explicit/implicit	Explicit/implicit
Implicit cross-border capacity pricing?	Not yet defined in the EU	Price differences

In continuous trading, bids follow a price-time priority and matching can be based on the pay-as-bid criterion or on the average bid price [41]. With continuous trading, bids are not sorted in a merit order list, as bids are matched at different prices depending on the bid price and the time when bids are submitted. In continuous trading, the same product (i.e., hourly energy product) can be traded several times within the trading period, in contrast with discrete auctions where trading times are limited by the number of sessions. Figure 2.2.1 shows how the market clearing is set in a continuous trading design, where bids are matched if the buy bid price is higher or equal to the sell bid price. In continuous trading, once the bids are submitted to the market, all the details of the bids can be viewed by all market participants. Because of this reason, generally buy and sell matched bid prices coincide. In Figure 2.2.1, the bids with the same number indicate matched bids by matching time, which follow the time and price priority.

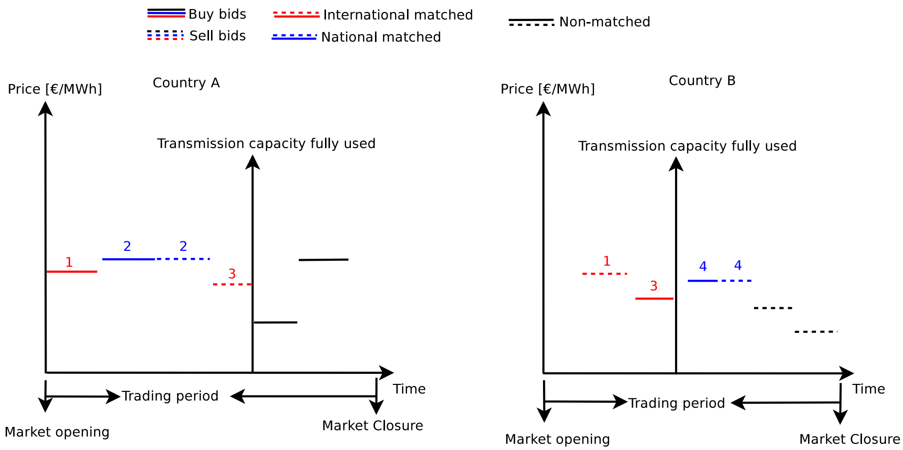


Figure 2.2.1: Cross-border trading in continuous intraday market

2.2.1 Cross-border intraday markets

A cross-border intraday market gives the possibility to balance intermittent RES-E across countries close to real-time. One of the critical aspects of cross-border intraday markets is the allocation and pricing of transmission capacity.

ENTSO-E [6] requires that cross-border transmission capacity should be allocated based on implicit methods. With implicit allocation of cross-border capacity, markets parties bid only for energy, and capacity is allocated implicitly. Whereas explicit methods market parties first have to bid for capacity, and once capacity is obtained, they bid in the energy market. Explicit allocation of cross-border capacity potentially leads to losses in terms of economic efficiency [42].

With a discrete auction design, in case of congestions, cross-border intraday capacity is based on the price differences as shown in Figure 2.2.2. The country with lower prices (country A) exports to country B. In case of congestions, the available transmission capacity limits the trade possibilities until the point that intraday available transmission capacity is fully used. In this case, market parties receive their national prices (P_A and P_B). The congestion rents correspond to the price differences times the exchanged energy (equal to the available transmission capacity). This system is currently applied in the day-ahead and intraday markets in the Iberian market (market splitting).

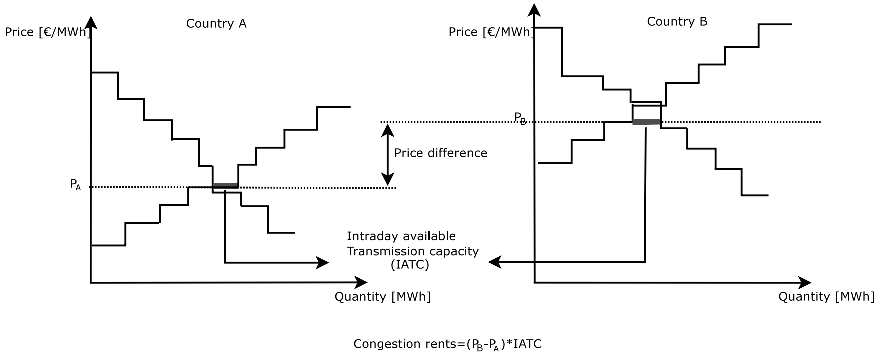


Figure 2.2.2: Cross-border trading in discrete auction intraday market

In continuous trading, cross-border bids are matched until transmission capacity is available. In Figure 2.2.1, the numbers represent the pair of bids that are matched between them (they can be matched with national bids or with bids from neighboring countries). For simplicity, the volumes of the bids are assumed to be the same. In continuous trading, it is not guaranteed that capacity is allocated to those that are willing to pay more for cross-border capacity. In addition, cross-border electricity trade can be reduced in comparison with sorting the bids in price merit order (as in a discrete auction market). However, one advantage of this design is that market parties can continuously update their positions in the market and they do not have to wait for a specific gate closure time.

2.2.2 Challenges of European intraday market integration

ACER [14] and ENTSO-E [6] agree in the implementation of continuous implicit trading (as the one already in place in Northern European countries). Additionally, the computation of transmission capacity available to the intraday market should be based on a flow-based approach (with a detailed grid representation). However, with continuous trading currently in place in Northern Europe, there are differences in the design options as shown in Table 2.2. APX [2] proposes a possible design for the European model that varies from the one used by Elbas (Nordic intraday market) and EPEX (German, French, Austrian and Swiss power exchange), but an agreement on a single design has not been reached. ENTSO-E [6] requires that pricing of transmission capacity reflects congestions in case of capacity scarcity. However, the current approach of zero price for transmission capacity does not fulfill this requirement.

Table 2.2: Existing differences between European intraday continuous trading designs

Design variables	Elbas	ComXerv (EPEX)	Target model [2]
Allocation of bottleneck income	First matched bids	Among buyers and sellers	Fully allocated to the TSOs
Capacity pricing	Zero price	Zero price	Linearly decreased by time
Re-buy capacity	Not allowed	Not allowed	Allow to re-buy capacity

ENTSO-E [6] agrees in the co-existence of regional auctions (such as the Iberian intraday market) with continuous trading. But the coexistence of both option should not negatively impact liquidity in the pan-european market, should not include discrimination between adjacent regions and should enable market participants to trade as close as possible to real-time. In addition, ENTSO-E requires that regulatory authorities shall review the compatibility between any regional solutions and the pan-European at least every two years. Further research is required in these aspects to study the possible incompatibilities of the coexistence of both designs and possible losses in terms of economic efficiency.

Pricing of transmission capacity in continuous trading

Pricing of transmission capacity in continuous trading has not been discussed in the literature. However, this is a requirement of ENTSO-E [6]. Figure 2.2.3 shows the capacity method proposed by APX [2]. According to this proposal the capacity price should be high when capacity is released and it should decrease by time. However, alternative methods can also be applied as shown in Figure 2.2.4. This proposal is also partially suggested by Willems [43]. The proposed approach has an inverse price behavior from that presented by APX [2].

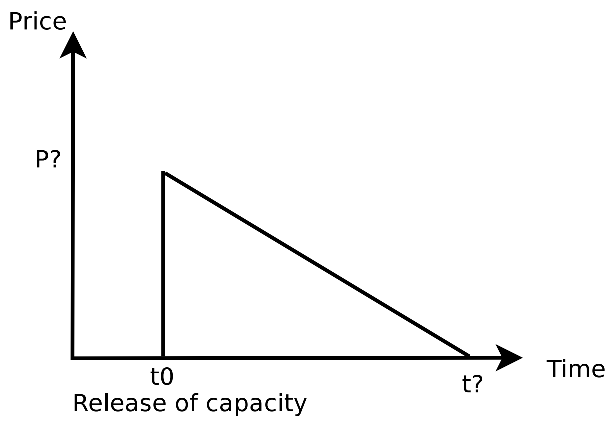


Figure 2.2.3: Pricing method for cross-border capacity in continuous intraday trading market proposed by APX [2]

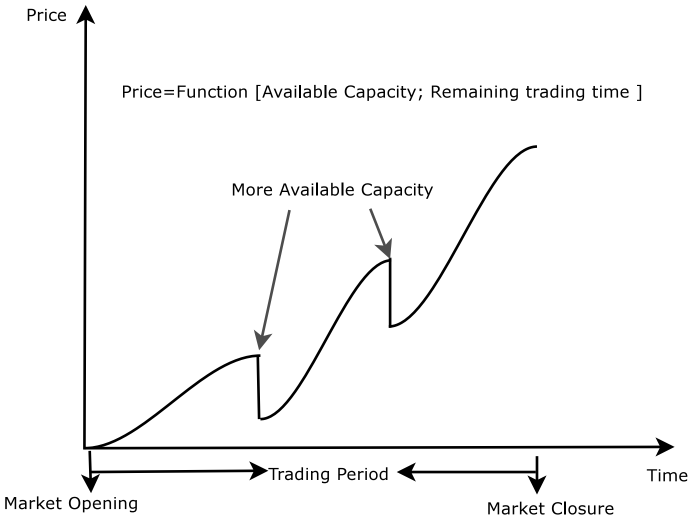


Figure 2.2.4: Alternative pricing method for cross-border capacity in continuous intraday market

The proposed pricing method for intraday transmission capacity in continuous trading markets considers the following aspects:

1. The price of transmission capacity should be dynamic and adapted to transmission capacity availability. In this way, the price for transmission capacity availability represents scarcity.

2. Closer to real time, more information about improved forecasts of intermittent RES-E is available. Therefore, intraday transmission capacity is more valuable closer to real-time and the price of transmission capacity should reflect it accordingly. This encourages market parties to trade as soon as they have information available, which has a positive impact on the disclosure of this information in the market.

3. If at the end of the trading period transmission capacity is not congested, the price of transmission capacity should be zero. This implies that if prices of transmission capacity have been charged, these charges can be returned.

4. The capacity prices should reflect the price differences between the countries. However, as explained earlier, in a continuous trading market, there is not a unique price per country. Therefore, the volume-weighted average can be used to compute the representative market prices per country.

The proposed methodology for transmission capacity pricing differs from the proposal of APX [2] in the sense that the price of transmission capacity is not decreasing by time, but instead it can increase. Additionally, the pricing methodology might not be linear as it depends on the transmission capacity availability. The exact computation of the price evolution over time is an important design variable that is out of the scope of this thesis, but it should be further analyzed. It is worth to mention that in continuous trading, any analysis of different prices schemes is difficult to evaluate in terms of social welfare. Some indicators can measure efficiency [41]: impact on local liquidity, number of users of transmission capacity and cross-border use of capacity. But these indicators are only proxies of social welfare.

2.3 The Spanish intraday market

This section was done in cooperation with Camila Fernandes from Comillas University who helped to analyze the Spanish market data. The authors want to thanks Prof. Tomás Gómez from Comillas University for his valuable comments.

This section presents the evolution of the Spanish intraday market in the few last years, and the relation with other short-term market mechanisms. Different market parties can behave differently in short-term markets depending on the uncertainties faced with respect to energy forecasts and the economic incentives from the different market mechanisms. In this section, the behavior of the different technologies in the Spanish intraday market is described by analyzing the energy traded in this market. One important aspect to analyze is to what extent RES-E reduce the imbalance through the intraday trading and what strategies are followed by these technologies in this market.

The remuneration of Spanish RES-E has changed significantly in the last years, not only by the amount but, also by the designs of the support schemes. These changes have implied changes in the bidding strategies of RES-E, specifically in the intraday market. This section explores to what extent support schemes design have also an impact on RES-E bidding strategies in the short-term markets.

This section explores whether the relative high liquidity in the Spanish intraday market is due to the discrete intraday trading itself, as it has been highlighted in the existing literature or if there are additional explanations. This chapter also focuses on possible inefficiencies that might be present in sequential short-term markets, such as the Spanish.

The remainder of the section is organized as follows: Section 2.3.1 briefly describes the organization of the Spanish short-term electricity market. Section 2.3.2 highlights the incentives to market parties to participate in the intraday market. Then, Section 2.3.3 studies the evolution of market prices and quantities, as well as the behavior of the different parties in this market. Section 2.3.5 discusses to what extent RES-E reduces energy imbalances through the intraday trading.

2.3.1 Overview of the Spanish electricity market

The Spanish short-term electricity markets comprise a sequence of markets which include the day-ahead and intraday markets, and the balancing services markets which consist of the following markets for specific services: technical and security of supply constraints management, FRR, RR, deviation management and additional upward reserve. The additional upward reserve market was recently established by the Spanish System Operator (SO) to handle situations of low online reserve margins. It is worth mentioning that in Spain, the primary reserve provision is a mandatory and non-remunerated service. The Spanish market parties can also trade electricity through bilateral contracts with physical delivery. Those market parties holding bilateral contracts have to inform the SO of the electricity contracted before the day-ahead market is held [44].

Once the day-ahead market is cleared, agents can adjust their schedules to compensate for equipment failures and energy forecast errors, or to apply strategic modifications in the intraday market. Since intermittent RES-E cannot participate in balancing services markets, the intraday market is the last option for these producers to adjust their production schedules according to updated generation profiles.

The Spanish intraday market is organized as six centralized auctions (hereinafter sessions), with different gate-closure times and energy-scheduling horizons (i.e. number of hours during which energy is traded). The intraday market lead-times (i.e. the difference between the last gate-closure time and the delivery hour) vary between 3.25 hours and 6.25 hours.

Table 2.3 presents the gate-closure and energy scheduling horizon of each intraday (ID) session[1], where 'D-1' refers to the day before operation and 'D' corresponds to the day of operation.

Table 2.3: Timing of the Spanish intraday sessions

	1º ID	2º ID	3º ID	4º ID	5º ID	6º ID	7º ID
Gate-closure	18:45 (D-1)	21:45 (D-1)	1:45 (D)	4:45 (D)	8:45 (D)	12:45 (D)	18:45 (D)
Trading hours	1-24 (D)	1- 24 (D)	5-24 (D)	8-24 (D)	12-24 (D)	16-24 (D)	21-24 (D)

Although the Spanish intraday market is divided into six auctions, the energy scheduling horizon of the first intraday session is divided in two. The first period takes place between 21:00-24:00 of 'D-1' corresponding to the last intraday session for the day of operation 'D-1'. A second period, comprising of all the hours of 'D', which corresponds to the first intraday session for the day of operation 'D'. Hereinafter, the former is referred as the seventh intraday session of 'D'.

[1]The table refers to the gate-closure times and scheduling horizons from October 2013, the Spanish market operator delayed by two hours the day-ahead market gate-closure and by one hour the first intraday market session gate-closure as a result of the integration in the European Market Coupling.

OMIE (the Iberian market operator) manages the day-ahead and intraday markets, without considering technical restrictions, which are handled later on through additional markets managed by each SO (i.e. the Spanish and the Portuguese). In Spain, if the market schedule does not comply with network constraints and/or reserve requirements are not enough the SO redispatches generation units through the procedure of management of technical constraints.

The need to procure reserves through this procedure increased significantly in order to guarantee enough online reserve margins as a result of the growing penetration of RES-E generation and the increasingly displacing of thermal generators from the day-ahead market. For this reason, in May 2012, the Spanish SO started procuring additional reserves through the additional upward reserve market [45]. This market is only called on when low reserve margins are detected, i.e. if, the day-ahead market schedule does not guarantee enough online reserves to balance generation and demand in real-time. After the upward reserve market is closed, the SO procures FRR capacity for each of the 24 hours of the day-ahead. Generators committed in this market receive the marginal price of the market (in €$/MWh$) for the capacity and an energy price (in €$/MWh$) in case the SO activates FRR. This energy price is given by the marginal price of the RR energy that would be required to replace the activated FRR according to the RR energy bid ladder.

The RR market is a market with mandatory offers, i.e. all conventional generators with available RR capacity must bid in this market. In this market the product procured is RR energy (there is no payment for capacity) and it is only cleared if RR energy is required in real-time. The units that provide RR receive an energy payment, corresponding to the marginal price of RR.

Finally, if the SO predicts that generation and demand imbalance, during a specific hour, is greater than 300 MW and energy can no longer be traded in the intraday market (i.e. deviation occurs after the gate-closure of a session of the intraday market session and before the first hour of the next session's scheduling horizon), the deviation management market is called. Available units may present energy offers and accepted bids receive the marginal price (in €$/MWh$).

2.3.2 Incentives to trade in the Spanish intraday market

This section analyzes the main incentives to trade in the Spanish intraday market. First, the main regulatory aspects in the Spanish market influencing the behavior of agents in the intraday market are discussed, followed by a brief analysis of the the Spanish imbalance settlement mechanism, which provides an incentive for generation units to reduce energy imbalances. The data presented in this section is publicly available in Red Eléctrica de España[2], unless it is specified differently.

[2]www.esios.ree.es

Management technical and security of supply constraints

Once the day-ahead market is cleared, the Spanish SO performs the management of technical constraints. Through this procedure, the SO redispatches generation whenever the market schedule does not comply with transmission security criteria or with interconnection capacity limits [46]. The SO may increase or decrease the generation scheduled in the day-ahead market to solve transmission constraints. Over 95% of the generation redispatched in Spain corresponds to increments of production (5% corresponds to decrements of production). In order to compensate for these increments (or decrements) of generation and reestablish the demand and generation in balance, the SO prompts a generation decrease (or increase) the schedule production from other generators. Decrements of production to balance generation and demand mainly affects the production of thermal power plants due to the priority dispatch of renewable generation.

The management of security of supply constraints was established by the Spanish government through the Royal Decree 134/2010 of February 2010 [47] and published as an operational procedure of the Spanish SO in October 2010 [48]. This procedure refers to the priority dispatch guaranteed to some generation units powered by Spanish coal. Under this procedure, if coal power plants with priority dispatch are not scheduled in the day-ahead market, the SO will redispatch these units as long as the scheduled production from renewable units is not reduced (i.e. they can only replace the production of other thermal power plants).

Due to the redispatch of generation through the above-mentioned procedures, some thermal generators have their day-ahead production schedule partially or completely reduced. These generators avoid being withdrawn from the day-ahead market by placing high bid prices, in this way they are not committed in that market and are then required to engage in the provision of balancing services. Moreover, retailers belonging to the same holding company as those thermal generators transfer part of their electricity demand to the intraday market, increasing purchase bids in the latter [49]. Besides, since these procedures mainly reduce the scheduled production of thermal generators, some companies owning both thermal and renewable power plants increase renewable production offered in the day-ahead market and later 'replace' renewable generation with thermal generation withdrawn from the day-ahead market in the intraday market.

The consequence of these procedures is that thermal generators may create an excess of supply occurs in the intraday market, resulting in overall lower intraday prices. With respect to the management of technical constraints, it is important to emphasize that generators which have their day-ahead generation schedule reduced by this procedure receive 15% of the day-ahead market price for this energy reduction (or the bid price to participate in this procedure). In this situation, these generators could offer energy to the intraday market at prices lower than their marginal costs. Generators which reduce their scheduled production due to security of supply constraints management are not financially compensated for that reduction.

Additional upward reserve market

Considering that the upward reserve market was created to handle the situation of low reserve margins resulting from the day-ahead market schedule, the provision of such reserve can only be provided by thermal generators which were not committed in that market. Due to this requirement, thermal units committed in the additional reserve market must sell their minimum technical generation to the intraday market.

Apart from the price for the energy sold in the ID market, units providing additional reserves receive the marginal price of the upward reserve market (in €$/MW$) for the whole reserve capacity committed. Since units providing additional reserves must be scheduled in the intraday market, in addition to the fact that they receive a capacity remuneration for the reserve provided, these generators can bid in the intraday market at prices lower than their actual marginal costs.

Imbalance pricing mechanism

In Spain, a dual imbalance pricing mechanism is applied as described in Appendix D. The imbalance prices in Spain are only related to the day-ahead market prices, without a strict relation between intraday prices and imbalance prices. Therefore, intraday prices give an arbitrage opportunity for BRPs between day-ahead market prices and imbalance prices. Figure 2.3.1 shows the monthly average imbalance prices as a percentage of the monthly average, day-ahead market prices from January 2010 until July 2013. During this period, average imbalance prices for negative imbalances were 11% higher than the day-ahead prices. It is worth mentioning that during April 2013, a high peak occurred due to high hydro and wind generation together with low levels of demand[3]. The imbalance prices for a positive imbalance during the studied period were on average 27% lower than the day-ahead prices. These price differences strongly penalize energy imbalances, providing an incentive to market parties to trade in the intraday market and avoid imbalanced positions.

[3] In April 2013 the monthly average imbalance price for negative imbalances was 68% of the monthly average day-ahead price for April 2013.

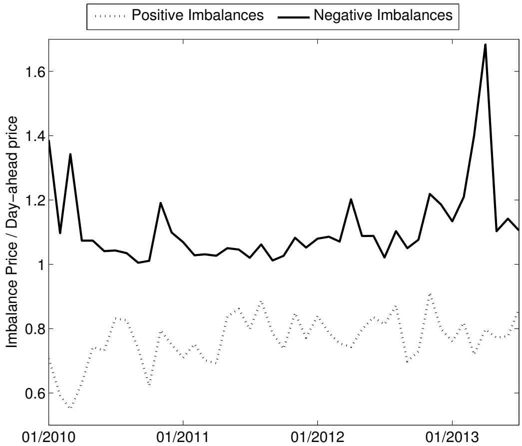


Figure 2.3.1: Monthly average imbalance prices

Balance responsibility

As explained earlier, BRPs are financially responsible for their schedule deviations. In Spain, although generators are allowed to present aggregated offers to the day-ahead market, market participants must send hourly schedules for each generation unit to the SO. The SO computes generation imbalances for (i) each generation unit not included in a balancing portfolio, (ii) each balancing portfolio, and (iii) a group of renewable generation units. In Spain, a balancing portfolio is defined as groups of dispatchable generation units, generally belonging to the same company, which are capable of providing FRR. In order to be included in a balancing portfolio, each generation unit must demonstrate its capability of providing both upward and downward FRR within the response speed required by the Spanish SO. In terms of imbalance costs, these units have an advantage compared to units not included in a balancing portfolio, since deviations from one unit within a certain balancing portfolio can be compensated by deviations from other units belonging to the same balancing portfolio.

As for renewable generators, since 2007 renewable units (or groups of renewable units) with an installed capacity higher than 1 MW are required to pay their full imbalance costs [50]. In order to participate in the markets, renewable units can be aggregated through a representative as long as they are under the same economic regime (support scheme) and belong to the same technology group. Although aggregation reduces energy imbalances, intermittent RES-E can be subjected to significant forecast errors. Therefore, these generators have an important incentive to participate in the intraday market.

2.3.3 Analysis of the Spanish intraday market outcomes

This section provides a detailed analysis of the Spanish intraday market results. First, intraday trading volumes and prices are analyzed, followed by the discussion on the behavior of intraday market participants.

Intraday market volumes

Figure 2.3.2 presents the hourly trading volumes in each intraday market session as a percentage of the trading volume in the day-ahead market from January 2010 to July 2013. These percentages were computed taking into account the scheduling horizon of each intraday session. For instance, the trading volume in the last intraday session were compared to the energy traded in the day-ahead market during the hours 21-24 of each day. It is observed that the first intraday session has the highest trading volumes. This is mainly the result of thermal production withdrawn from the day-ahead market due to the management of technical and security of supply constraints. These units are then rescheduled in the first session of the intraday market. Last intraday sessions (6 and 7) also have relatively high volumes proportional to the hours traded (as a result of RES-E forecast improvements), but these volumes are significantly lower than the ones of the first session.

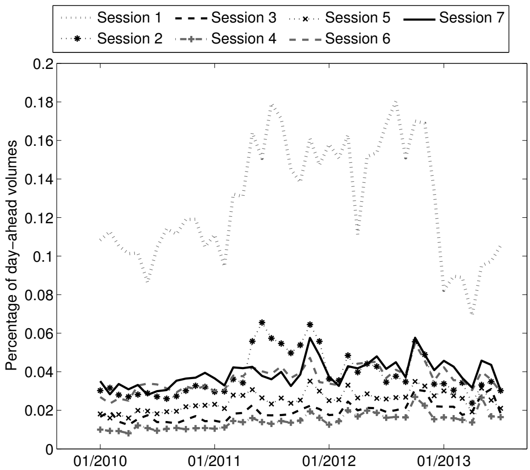


Figure 2.3.2: Trading volume in the intraday market as percentage of trading volume in the day-ahead market

Figure 2.3.3 illustrates the energy volumes that are withdrawn from the day-ahead market due to the redispatch of generation that is required to solve technical and security of supply constraints.

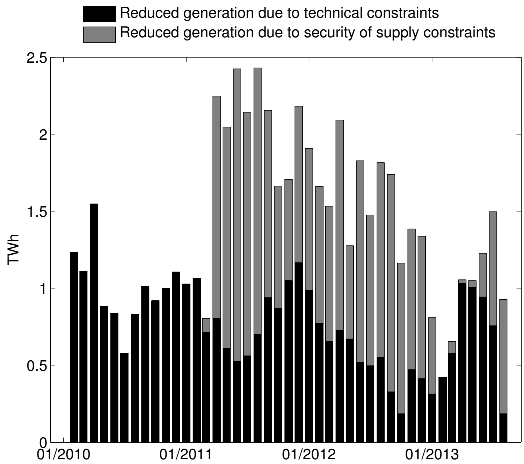


Figure 2.3.3: Redispatch actions for the management of technical and security of supply constraints

Figure 2.3.2 and Figure 2.3.3 clearly show that the management of security of supply constraints established by the Spanish government by the end of 2010 had an impact on the intraday trading volumes, which presented a significant increase in that period. Regarding Figure 2.3.3, it can be observed that both series (Figure 2.3.3) present downward trends. The reduction in the volume of energy redispatched due to technical constraints can be explained by the creation of the additional upward reserve market, which has been avoiding the redispatch of thermal generators to comply with online reserve requirements. Furthermore, during the first months of 2013 high wind and hydro generation prevented coal power plants from being redispatched through the security of supply constraints management (since coal production cannot replace renewable generation). This also had an impact in the intraday market: since fewer coal units were scheduled through the security of supply constraints management fewer thermal power plants were withdrawn from the day-ahead market. This led to less activity in the intraday market.

Figure 2.3.4 presents the additional upward reserve capacity procured by the Spanish SO since the establishment of this market. As it can be observed, this type of reserve is bought mainly during autumn and winter months corresponding to periods of highest wind generation levels in Spain. Therefore, it can be expected that its impact on intraday trading volumes and prices will be higher during those months with high wind generation. Despite this, since not all of this reserve capacity is offered to the intraday market, its impact on intraday market is expected to be lower than the influence of the management of technical and security of supply constraints.

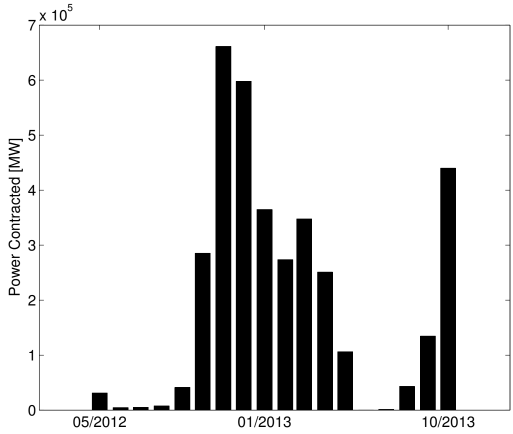


Figure 2.3.4: Monthly contracted additional upward reserve

Intraday prices

In order to analyze intraday prices, the day-ahead premium has been computed. The day-ahead premium or risk premium is defined as the difference between forward prices (day-ahead market prices) and spot prices (intraday prices). Most of the studies that analyze the risk premium use the ex-post risk premium to avoid unrealistic assumptions about expected spot prices. As discussed in Haugom and Ullrich [51], the ex-post risk premium can be broken down into an ex-ante risk premium and a forecast error. However, it is usually assumed in the literature that the ex-post risk premium is a good proxy for the ex-ante premium. Here, the realized risk premium is defined in (2.3.1).

$$RP_t = P^D_{h,t+1} - P^I_{h,t} \tag{2.3.1}$$

Where $P^D_{h,t+1}$ is the day-ahead price for the hour (h) of the next day (t+1). $P^I_{h,t}$ is the volume-weighted average intraday price for the hour (h) of the current day (t), note that some of the trade can occur in the intraday market from the day before.

Regarding intraday prices, volume-weighted averages are used to consider the importance of trading volumes of each intraday session.

According to the results of this analysis (Table 2.4), day-ahead premia are positive and statistically significant for most of the hours of 2011 and 2012. The average day-ahead premium during the period 2011-2012 is 1.3 €$/MWh$. This implies that intraday prices are generally lower than day-ahead prices, as a result of an excess of supply in the intraday market.

Table 2.4: Spanish day-ahead premia

	2011			2012			2013		
	Day	Peak	Off-Peak	Day	Peak	Off-Peak	Day	Peak	Off-Peak
Premia	1.47***	1.65***	1.32***	1.13***	1.34***	1.17***	0.95***	1.54***	0.46*
Std.Dev.	4.33	3.85	4.68	4.43	3.99	4.74	5.68	5.27	5.95
Skewness	0.84	2.54	0.10	0.31	0.57	0.21	0.09	0.75	-0.22
Kurtosis	12.67	20.70	8.99	5.07	5.42	4.72	7.20	7.58	6.74

*Significant at 90%; *Significant at 95%; ***Significant at 99%

The t-Statistics are based on the heteroscedastic and autocorrelated consistent covariance matrix estimator.

During the first semester of 2013 the day-ahead market premium decreases. This reduction can be explained by lower day-ahead market prices, which were influenced by high wind and hydro production during that period.

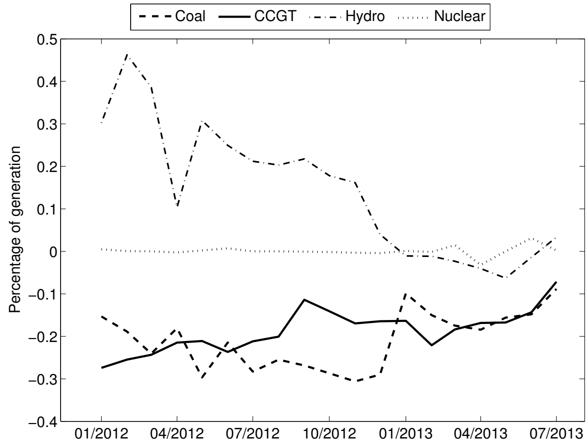
2.3.4 Behavior of intraday market participants

Conventional generators

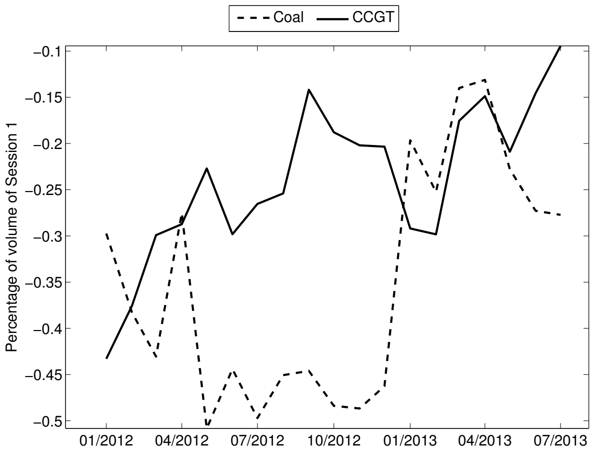
Figure 2.3.5a shows the participation of conventional generators in the intraday market as a percentage of each technology's generation. Negative values indicate to a net selling position (i.e. total sales are greater than total purchases) and positive values correspond to a net purchasing (i.e. total purchases are greater than total sales).

It can be observed in Figure 2.3.5b that coal and combined cycle (CCGT) power plants sell a significant percentage of their total production in the first session of the intraday market. During the period between January 2012 and July 2013, these technologies together represented at least 18% up to 78% of the total energy sales in the intraday market. This is because these technologies are the most affected by the management of technical and security of supply constraints due to the priority dispatch of renewable generation.

Regarding the remaining technologies, hydro power plants mainly buy energy in the intraday market, which can be justified by the strategy adopted by some companies owning both hydro and thermal power plants when the latter are withdrawn from the day-ahead market by the management of technical and security of supply constraints. Finally, the participation of nuclear power plants in the intraday market is very limited.



(a) Net volumes in the first intraday session as percentage of technologies' generation



(b) Volumes of coal and CCGT as percentage of first session volumes

Figure 2.3.5: Participation of conventional technologies in the first session of the intraday market

Demand

Figure 2.3.6 presents the participation of demand agents in the first intraday market session as percentage of their final market schedules. "Last-resort retailers" refers to retailers that provide electricity to small consumers (i.e. consumers with a contracted capacity below 10 kW), which in 2012 represented around 20% of total demand [52]. These retailers belong to the five biggest electricity companies active in the Spanish electricity market. Liberalized consumers, either directly or through retailers, represent the highest share of demand in the intraday market: on average 79% in the studied period. During this period, these consumers mainly bought energy in the intraday market. As mentioned in Section 2.3.2, this can be partially explained by the strategy adopted by some companies owing generation withdrawn from the day-ahead market and transferring part of their demand from that market to the intraday market in order to increase purchase offers in the latter. Apart from that, some retailers are arbitrating between day-ahead market prices and intraday prices.

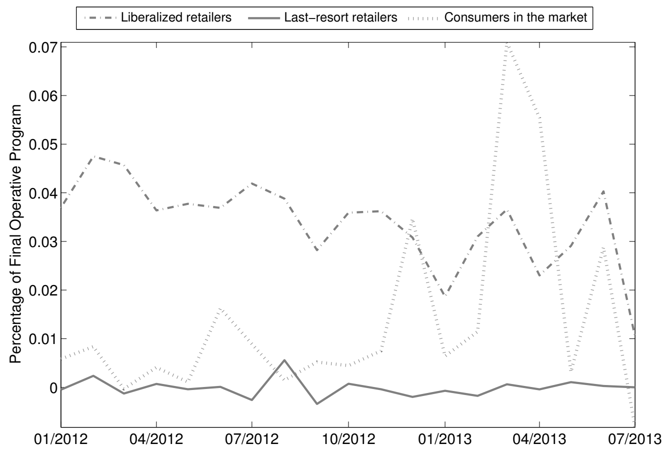


Figure 2.3.6: Demand-side participation in the first session of the intraday market

Renewable generators

In order to analyze the participation of renewable units in the intraday market it is important to understand how these generators are remunerated. Until 2012, renewable generators in Spain could choose either to receive a feed-in-tariff (FiT) or a feed-in-premium (FiP) above the day-ahead market price. The hourly income (π_h) of RES-E under the FiP scheme is represented in (2.3.2).

$$\begin{aligned}\pi_h = P_h^D Q_h^D + \textstyle\sum_{i=1}^7 Q_{hi}^I P_{hi}^I + \left(Q_h - Q_h^D - \textstyle\sum_{i=1}^7 Q_{hi}^I\right) P_{hi}^+ + \\ \left(Q_h - Q_h^D - \textstyle\sum_{i=1}^7 Q_{hi}^I\right) P_{hi}^- + Q_h * Premium\end{aligned} \quad (2.3.2)$$

Where Q_h^D is the energy sold in the day-ahead market, $\sum_{i=1}^7 Q_{hi}^I$ is the total energy sold in all the different intraday market sessions[4] (i represents the intraday session and h the traded hour), and Q_h is the final energy delivered. P_h^D, P_h^I, P_h^+, P_h^- are the day-ahead, intraday and imbalance prices for positive and negative imbalances,

[4]Notice that depending on the hour of the day, the energy traded for a specific hour can be traded from 3 to 7 times.

respectively. Additionally, the premium scheme also has price cap and floor which set limits for RES-E income.

In equation (2.3.2), the first term introduces the remuneration renewable units receive for selling energy in the day-ahead market and the second term refers intraday market trading, which could correspond to a payment (in case of energy being bought) or to a revenue (in case of energy being sold). The third and fourth terms of the equation correspond to the payment or revenue resulting from imbalances. If the system imbalance during one hour is negative (i.e. actual production is lower than the scheduled one), the fourth term is active and the third term is zero. If the system imbalance during one hour is positive (i.e. actual production is higher than the scheduled one), the third term is active, and the fourth term is zero. Finally, the last term corresponds to the premium paid for every MWh produced.

Equation (2.3.3) shows the feed-in tariff scheme applied to RES-E in Spain.

$$\pi_h = \left[P_h^D Q_h^D + \sum_{i=1}^{7} Q_{hi}^I P_{hi}^I\right] + \left[\left(Q_h - Q_h^D - \sum_{i=1}^{7} Q_{hi}^I\right) P^+ + \left(Q_h - Q_h^D - \sum_{i=1}^{7} Q_{hi}^I\right) P^-\right] + \left[Q_h * Tariff - Q_h P_h^D + \sum_{i=1}^{7} Q_{hi}^I \left(P_h^D - P_{hi}^I\right)\right] \tag{2.3.3}$$

In equation (2.3.3), the contents in the first square brackets refer to the remuneration computed by the market operator (MO), which corresponds to the energy sold in the day-ahead and intraday markets. The contents in the second square brackets refers to the revenue or payment computed by the SO corresponding to positive or negative imbalances. Finally, content in the third square bracket corresponds to the difference between the FiT and the revenue obtained in the market, which is calculated by the regulator. The last term of the third component corresponds to the adjustment in the remuneration due to day-ahead and intraday market prices differences.

Notice that under the tariff scheme, although support schemes payments are divided into different components (in which market prices appear), the final RES-E income under FiT does not depend on the day-ahead nor intraday prices, as they are cancelled out. With the premium scheme the income of RES-E depends on the electricity prices (day-ahead and intraday). Therefore, arbitrage between these markets can be profitable for RES-E under FiP.

As discussed in Section 2.3.2, generally imbalance prices for positive imbalances deviate from day-ahead market prices more than prices for negative imbalances. This provides an incentive for BRPs to strive for negative imbalances. Notice that for both remuneration schemes, RES-E do receive support schemes in the case of long-positions. Another possibility is to not provide the support schemes in case of positive imbalances to further encourage RES-E generators to be balanced. However, additional distortions can be introduced with this, as RES-E generators would tend to avoid positive imbalances.

In 2013, although generators could still choose between the feed-in tariff scheme and the market option, the Spanish government [53] removed the premium above the market price. For this reason, in 2013 all renewable generators moved to the FiT mechanism.

Table 2.5 presents the support scheme chosen by renewable generators in 2011, 2012 and 2013 until July. For 2011 and 2012, the final remuneration per energy delivered for all renewable generators, with exception of cogeneration (CHP)[5], was higher under the FiP than under FiT scheme. This further incentivized RES-E to choose the FiP scheme. As shown in Table 2.5, the major part of renewable production was sold under the FiP scheme. Only PV and CHP generators remained (mainly) under the FiT scheme.

Table 2.5: Remuneration and energy produced under the feed-in tariff and feed-in premium schemes

(a) Remuneration (€/MWh)

	2011		2012		2013*
	FiT	FiP	FiT	FiP	FiT
Cogeneration	110,85	88,00	126,61	92,22	126,83
Solar PV	359,35	-	368,93	-	431,47
Solar Thermal	291,65	-	296,26	328,90	296,64
Wind	78,35	90,10	80,11	86,29	82,90
Hydro	84,79	88,52	85,96	86,50	83,53
Biomass	122,90	126,37	130,12	13,363	126,78

(b) Energy produced (GWh)

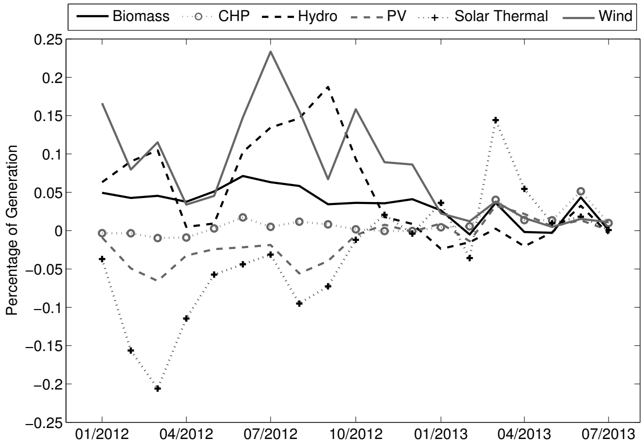
	2011		2012		2013*
	FiT	FiP	FiT	FiP	FiT
Cogeneration	21.670	3.390	22.547	4.340	13.447
Solar PV	7.425	-	8.161	-	5.023
Solar Thermal	1.779	-	1.167	2.266	2.630
Wind	9.765	31.718	11.781	36.085	32.428
Hydro	2.113	2.616	1.714	2.383	4.963
Biomass	971	2.421	824	2.955	2.689

Figure 2.3.7 shows the participation of renewable generators in the first session of the intraday market. It can be observed that for technologies mainly under the FiP option (i.e wind, solar thermal, biomass and hydro) trading volumes in the intraday market decreased considerably in 2013. This is related to the fact that in 2013 all renewable generators in Spain were under FiT. Therefore, they “lost” the incentive to arbitrate between the day-ahead and intraday market prices. Figure 2.3.7 shows that in 2012 the technologies under the FIP option mainly bought in the intraday

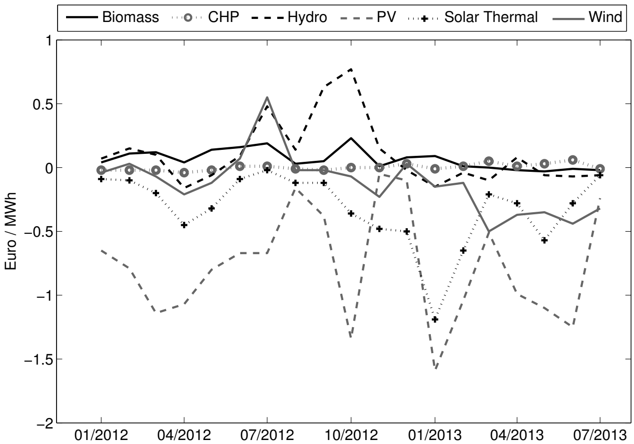
[5]Although CHP is not a renewable source, these units are included in the analysis as they are part of the “special regime” and receive support schemes as RES-E.

market due to lower prices in comparison with the day-ahead market. Two types of strategy adopted by some electricity companies in that period can justify this outcome: (i) price arbitrage and (ii) replacement of thermal generation bids with renewable production offers to the day-ahead market.

Figure 2.3.7b presents the profits/losses resulting from selling (or buying) energy in the intraday market at higher (or lower) prices than the in day-ahead market. As it can be seen in general, the technologies that are making profits in the intraday market are the ones that can arbitrate between day-ahead and intraday market prices. In most cases these technologies make profits by buying energy in the ID market at lower prices. Although the figure displays profits (and losses) for all technologies, as explained earlier, the remuneration of power plants under the FiT does not depend on day-ahead and intraday market prices (equation 2.3.3).



(a) Volumes of RES-E traded in the first session of the intraday market



(b) Intraday costs for RES-E as percentage of total generation (€$/MWh$)

Figure 2.3.7: Participation of RES-E in the intraday market

Figure 2.3.8 presents the participation of wind generators in the different intraday sessions as a percentage of actual generation in the corresponding trading hours of each session. As shown in Figure 2.3.8, the energy traded by wind generators in the first intraday sessions has significantly decreased from 2012 to 2013. This can be explained by the fact that during the 7-month period January 2013 to July 2013 all renewable generators were under the FiT scheme and, consequently, the incentive to arbitrate between the day-ahead and intraday market prices was eliminated.

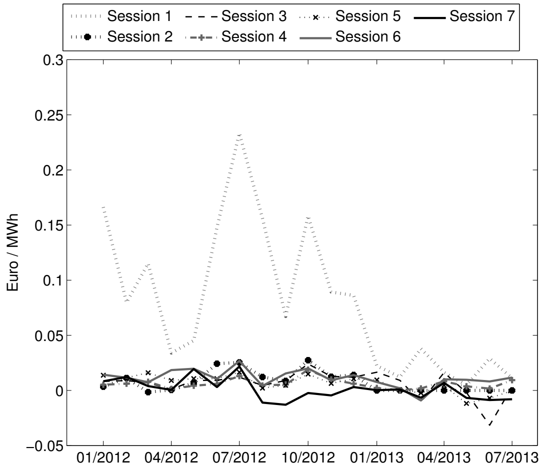
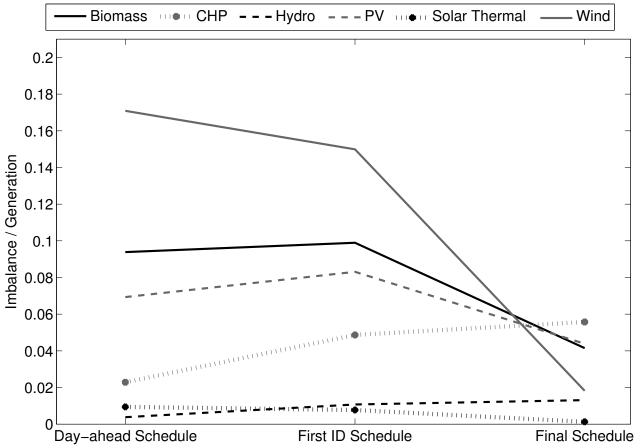


Figure 2.3.8: Net wind power volumes on the different sessions of the intraday market

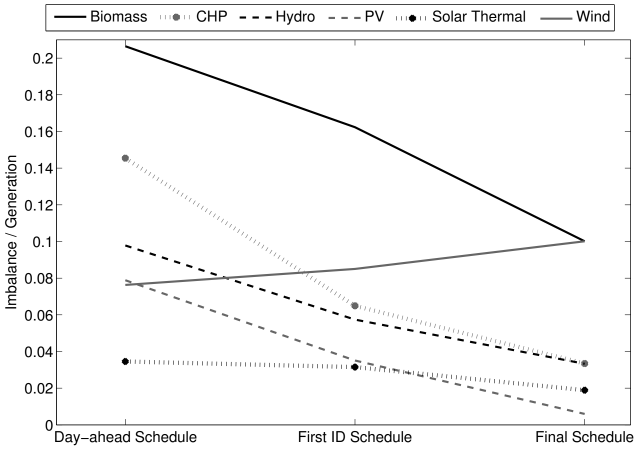
As a result of the strategy adopted by renewable generators of overselling in the day-ahead market, the Spanish SO increased the amount of reserves procured through the management of technical constraints. The Spanish Regulator estimated that the extra cost imposed to the system by the financial arbitrage between the day-ahead and the intraday markets was approximately €90 millions in 2010 and €46 millions in 2011 [54]. Although the arbitrage level increased in 2011, the reserve cost was reduced due to the mechanism for management of security of supply constraints introduced in the Spanish market in that year.

2.3.5 Reducing renewable energy imbalances in the intraday market

It was observed that some renewable generators have been trading in the first intraday session to arbitrate between day-ahead and intraday market prices. These generators have incentives to trade in the intraday market to adjust their schedules and reduce imbalance costs (as discussed in Section 2.3.2).. Figure 2.3.9 and Figure 2.3.10 present the positive and negative deviations of renewable generators with respect to: (i) their schedules in day-ahead market, (ii) the first session of the intraday market and (iii) the final schedules as percentages of actual renewable production in 2012 and 2013, respectively. “Final schedule” refers to the generation schedule after the last intraday session.



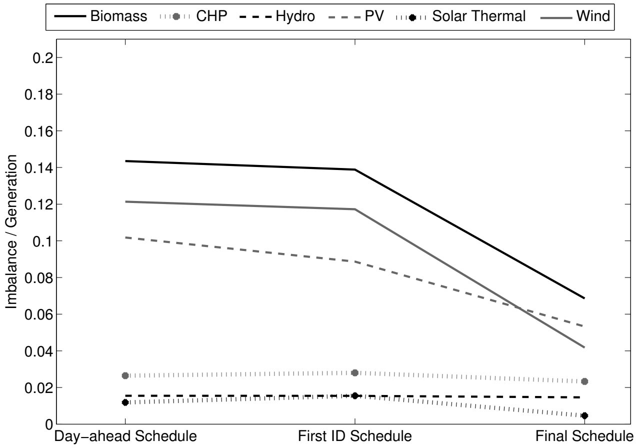
(a) Positive Imbalances



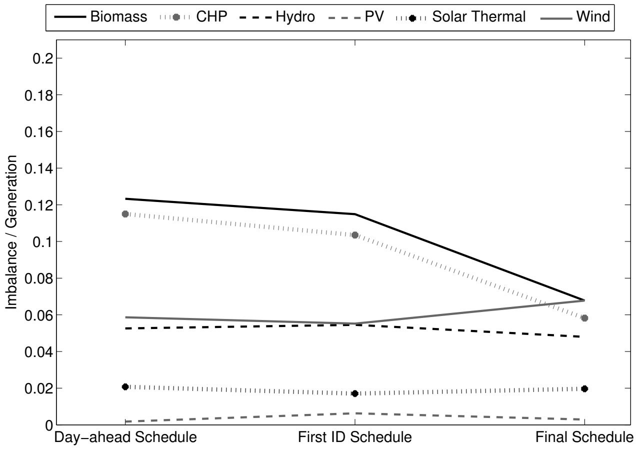
(b) Negative Imbalances

Figure 2.3.9: Imbalances per RES-E technology in 2012

Figure 2.3.9b and Figure 2.3.10b show that, in general, renewable generators are reducing their schedule deviations by participating in the intraday market in both 2012 and 2013. Nevertheless, it can be observed that RES-E generators under the FiP option changed their behavior in the day-ahead market, since the incentive to arbitrate between day-ahead and intraday market prices was eliminated. These generators reduce their negative deviations with respect to the day-ahead market scheduled from, on average, 13% in 2012 to 7% in 2013.



(a) Positive Imbalances



(b) Negative Imbalances

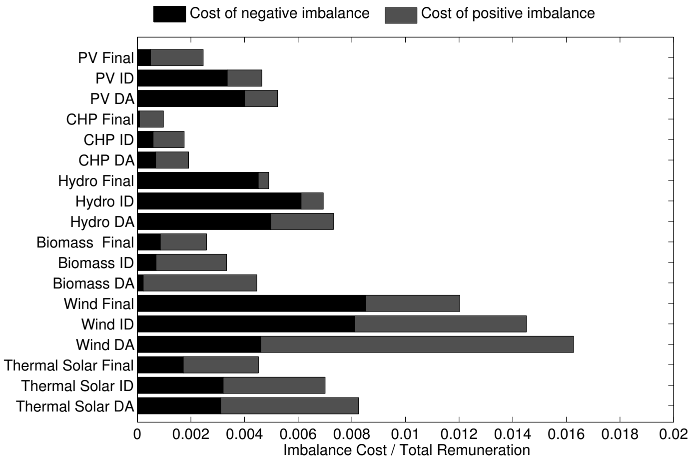
Figure 2.3.10: Imbalances per RES-E technology from January until July 2013

Another interesting outcome of arbitrating between day-ahead and the first intraday market prices is that, while in 2013 RES-E generators were mostly adjusting their schedules after the first session of the intraday market, in 2012 they adjusted a significant share of their negative deviations in the first intraday session: in 2012 negative RES-E imbalances were reduced by 29% in the first intraday session and by 39% in the remaining intraday sessions; in 2013, these imbalances were decreased by 7% in the first intraday sessions and by 38% in the remaining sessions. Despite this, final imbalances do not change significantly from one year to the other. On average, positive final imbalances corresponded to 2.9% and 3.4% of actual generation in 2012 and 2013, respectively, while negative imbalances corresponded to 4.9% and 4.4%.

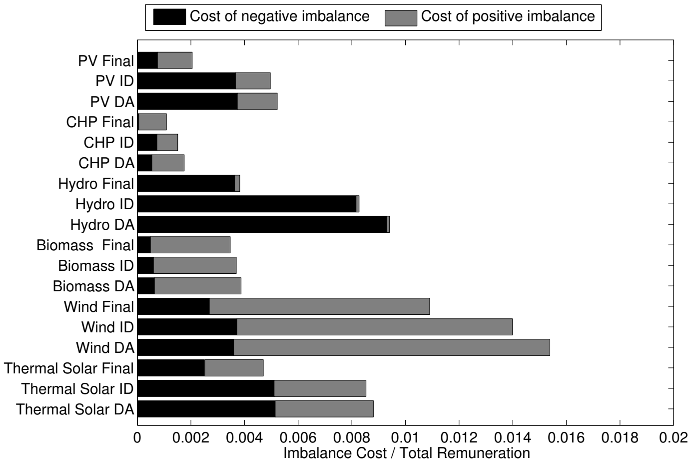
Regarding this, it is worth noting that even though these producers are participating in the intraday market to adjust their generation schedules final imbalances remain an important share of their actual production. In this way, bringing intraday market gate-closure closer to real-time could allow RES-E generators to reduce generation imbalances even further and favor their integration into the system.

In Figure 2.3.11, "DA" represents the imbalance costs RES-E generators would have incurred if they could not adjust their schedules in the intraday market. "ID" represents the imbalance costs producers would have incurred if the first intraday session was the last trading prior gate-closure. "Final" shows the actual imbalance costs incurred by RES-E generators. For "DA" schedule, imbalance costs are computed as the costs of not having a perfect forecast at the day-ahead market gate-closure. For positive imbalances, this corresponds to the opportunity cost of selling the "additional" energy at the day-ahead market price, instead of selling it at the positive imbalance price. For negative deviations it represents the extra cost of buying energy at the negative imbalance price in comparison with buying it at the day-ahead market price. he same reasoning applies for "ID" schedule.

Figure 2.3.11 shows that, in general, RES-E generators reduce their imbalance costs by trading in the different sessions of the intraday market. Even though the first intraday session is the most liquid session of the intraday market, RES-E producers reduce a greater share of their imbalances after this session. In 2012, total RES-E imbalance costs were reduced by 12% in the first intraday session and by 28% in the remaining intraday sessions, while in 2013 total imbalance costs were reduced by 7% in the first session and by 36% in the remaining ones. In both years, final imbalance costs of RES-E technologies were reduced by approximately 40% due to the participation of producers in the intraday market.



(a) 2012



(b) 2013

Figure 2.3.11: Imbalance costs for RES-E

Despite imbalance costs representing relatively small share of the total renewable generators' remuneration – approximately 0.5% on average – they would represent a much more significant share of RES-E producers' revenues when support schemes phase out. This is the current situation of some RES-E producers due to the new regulation for renewable generation established by the Spanish government [55]. This reform eliminates the old support schemes (FiT and FiP) and links renewable producers' remuneration directly to their participation in the electricity markets. The reform includes an additional remuneration for those installations which have not recovered yet their investment costs, taking into account the total income already perceived under the previous regulatory framework. This additional remuneration guarantees those units a profit margin of 7.5%, before taxes, during the whole lifetime of the installation.

2.4 Continuous trading: the German intraday market

The author wants to thank the collaboration of Arthur Henriot from the European University Institute for the discussions about the German intraday market. The work presented in this chapter is complemented with Hagemann and Weber [56], which use the dataset from 2010—2011 and further analyze liquidity in the German intraday market.

The European Power Exchange (EPEXSPOT) operates the German day-ahead and intraday markets. The German day-ahead market takes place at 12h00. The intraday market starts at 15:00 until 45 minutes before delivery for hourly and block hourly products. Since 2012, it is also possible to trade 15 minutes products. For the period from 2011 to September 2013, all the hours presented market results for the day-ahead and intraday markets.

The German intraday market is based on continuous trading, this means that bids are continuously submitted to the market after the opening and before the gate closure time (45 minutes before real time). All bids are stored in an order book and they are visible to all market parties until they are matched or cancelled. The matching algorithm follows a time-price priority, which means that bids are matched depending on the arrival time and the price of the bids. The bids are stored in an order book until they are matched. It is relevant to highlight that the book order is available for market participants. This means that market participants can see previous bids submitted to the market before bidding. Because of this, the matching process is different from a marginal pricing, usually buy and sell bids coincide, otherwise they are matched at the average price between both bid prices. Non-executed orders remain in the book until they are expired or cancelled. Throughout the trading session, participants have access to all orders, as well as to the details of previous bids (i.e. price, quantity and time). The intraday bid prices can vary between $-9999\,€/MWh$ to $9999\,€/MWh$.

2.4.1 Insights from the German intraday market data

The trading volume in the German intraday market has been increasing from 2009, due to the obligation of SOs to manage RES-E energy forecasts through the day-ahead and intraday markets [9]. Figure 2.4.1 shows the traded volumes in the German day-ahead and intraday markets from 2009 to 2013. Although trading volumes slightly increased in in the intraday market, these volumes are still relative low.

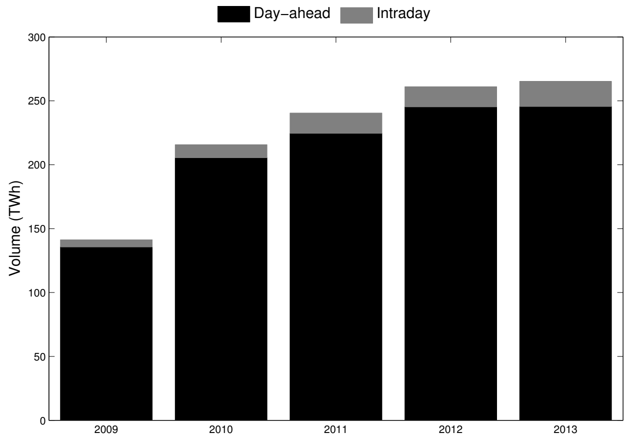


Figure 2.4.1: German day-ahead and intraday volumes

EPEX Spot has provided, through the Florence School of Regulation, bid data from the German intraday market, including bids (matched or not) in the intraday markets for 2011. However, the data provided do not contain information about market participants or specification by technologies, which considerably limits the analysis.

In order to have consistent analysis, the time-period considered is from April 1st 2011 to December 13th 2011. These two dates were chosen as the lead-time period was shortened from 75 to 45 minutes on March 29th, and quarter-hourly bids were introduced on March 14th.

Table 2.6 shows the distribution of traded volumes in the Germany intraday market for 2011. Notice that depending on the hour of the day, the trading period differs, as the trading period increases for those hours at the end of the day. Table 2.6 shows that a significant part of the trade occurs at the opening of the market, maybe to adjust positions from the day-ahead market. However, trade increases close to the production hour[6]. This can be mainly to the last forecasts from RES-E.

[6]The production hour refers to each hour of the year or the contract hour for which buy and sell bids are summited.

Table 2.6: Volume distribution in the German intraday market for 2011

Set of hours	Length of trading	Last 15 mins	Last 3 hs 15	First four hours
00:00h-04:00h	8 h 15 min to 11 h 15 min	7%	42%	43%
04:00h-08:00h	12 h 15 min to 15 h 15 min	7%	35%	35%
08:00h-12:00h	16 h 15 min to 19 h 15 min	9%	50%	27%
12:00h-16:00h	20 h 15 min to 23 h 15 min	8%	49%	22%
16:00h-20:00h	24 h 15 min to 27 h 15 min	7%	41%	19%
22:00h-24:00h	28 h 15 min to 31 h 15 min	5%	32%	23%

2.4.1.1 Price behavior

This section analyzes the main behavior of the German intraday prices. The analysis of all the bids including non-matched ones gives an idea of bidding behavior of buyers and sellers.

As the German intraday market is a continuous trading market, which is open from the day ahead until 45 minutes before real time, traders can submit prices with different volumes at different times. Therefore, in order to consider the relative importance of the different bid volumes, the descriptive statistics are weighted by the bid volume. The volume-weighted average and standard deviation are computed for each production hour (h) and for each bidding hour (bh)[7]. These basic statistics are defined as follows:

$$\mu^*_{h,hb} = \frac{\sum_{i=1}^{N_i} Q_{h,bh,i} P_{h,bh,i}}{\sum_{i=1}^{N_i} Q_{h,bh,i}} \tag{2.4.1}$$

Where:

$P_{h,bh,i}$ is the bid price (i) for each production hour (h) and each bid hour (bh).

$Q_{h,bh,i}$ is the bid quantity (i) for each production hour (h) and each bid hour (bh).

$\mu^*_{h,bh}$ is the volume-weighted average for each production hour (h) and each bid hour (bh).

N_i is the total number of observations per each production hour of the year (h) and each bid hour (bh).

The volume-weighted variance $\left(\sigma^{2*}_{h,bh}\right)$ is defined as:

[7] bh=1 means from 45 to 60 minutes before the contract hour. bh=2 means from 1 hour to 2 hours before the contract hour, and so on. Finally, bh=32 means bid hour from 31 hours to 32 hours.

$$\sigma^{2*}_{h,bh} = \frac{\sum_{i=1}^{N_i} Q_{h,bh,i} \left(P_{h,bh,i} - \mu^{*}_{h,bh} \right)}{\sum_{i=1}^{N_i} Q_{h,bh,i}} \tag{2.4.2}$$

In order to have an overview of these descriptive statistics for bid prices, the volume-weighted average and standard deviation (root-square of the variance) are computed for the whole year. These values are computed first obtaining these statistics for each production hour and then the yearly average.

There is high variability of bid prices during the year, measured as the volume-weighted standard deviation, which is significantly high as shown in Table 2.7.

Table 2.7: Yearly volume weighted average and standard deviation for German intraday bid prices (€/MWh)

Volume-weighted	**Buy bid prices**	**Sell bid prices**	**Buy bid prices***	**Sell bid prices***
Average	49.69	60.10	49.53	57.64
Standard deviation	45.52	118.14	15.40	15.07

*Bid prices corrected for outliers.

For non-matched bids, there are extreme values that affect the main descriptive statistics. Therefore, in order to remove the effect of outliers, the values that fall out of three standard deviations are removed.

Once outliers are removed (0.11% of the observations for buy bid prices and 0.046% of the observations for sell bid prices) the standard deviation decreases substantially. The high variability of bid prices is explained partially because these yearly descriptive statistics ignore all the different seasonalities presented in the electricity prices: monthly, weekly or daily. Additionally, there are bidding times for each hour that can affect the price levels.

2.4.1.2 Relation between bid prices and bidding hours

Once the previous defined statistics are computed, it is analyzed if there is a correlation statistically significant between the bidding hours and the weighted average and standard deviation. This gives an idea on how bid prices behave for each production hour at different bidding hours. For this purpose, the correlation coefficient between the average bid prices and bidding hours is computed as follows:

$$\rho_{\mu_{h,bh},bh_h} = \frac{cov\left(\mu_{h,bh}, bh_h\right)}{\sigma_{\mu_{h,bh}} \sigma_{bh_h}} \tag{2.4.3}$$

The same coefficient is computed for the volume-weighted standard deviation. Both series of correlation coefficients are computed for all the hours of the year. The yearly average values for these correlations are shown in Table 2.8. A positive correlation means that when bidding time is closer to real time (bidding time decreases), the volume-weighted average or standard deviation decreases. The correlations shown in Table 2.8 consider just the data corrected for the outliers as they have a significant impact, especially on weighted average standard deviation. The columns with asterisks show the average of correlation coefficients that are significant at 5% level. For this computation those correlations for production hours that are not statistically significant at 5% are withdrawn.

Table 2.8: Correlations between bidding hours and volume-weighted average and standard deviation of bid prices

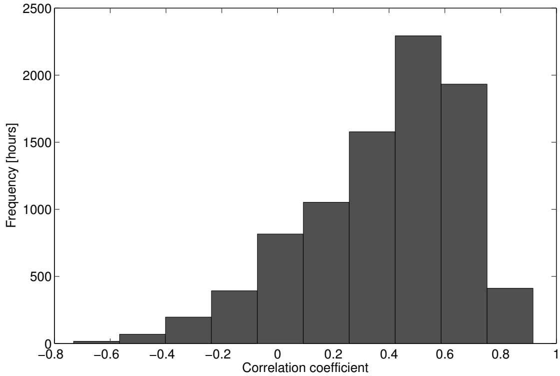
Volume-Weighted	Buy bid prices	Sell bid prices	Buy bid prices*	Sell bid prices*
Average	-0.25	0.30	-0.48	0.53
Standard Deviation	-0.01	0.04	0.06	0.16

*Significant correlations at 5% level

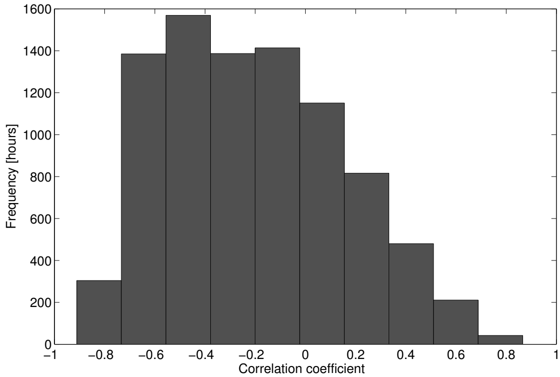
In general terms, buy bid prices increase closer to real time while sell bid prices decrease. This shows that the sellers at the German intraday market initially sell at higher prices, and for bidding hours closer to real time, they decrease the bid prices. Sellers start selling at high bid prices, and if they cannot find a counterpart to match their bids they might decrease prices. The opposite happens for buyers, closer to the real time they are willing to buy at higher prices. Additionally, these price behaviors might respond to changes in price expectations, due to new information such as updated energy forecasts.

With respect to the standard deviations, Table 2.8 shows low correlations between standard deviations and bidding time for buy and sell prices, which is mainly because standard deviations are high both at the market opening and hours closer to real time.

Figure 2.4.2 shows the correlations between bidding price and bidding hour. Sellers clearly submit bids at high prices at the market opening and reduce the prices closer to the market closing time. Although buyers do the opposite, buyers submit bids at high prices at the end of the market maybe to avoid negative imbalances.



(a) Sell prices



(b) Buy prices

Figure 2.4.2: Correlation between bidding prices and biding hour

2.4.1.3 Challenges in a continuous trading intraday electricity market: compute accurate liquidity measures and bidding strategies

In financial markets, a wide range of literature has studied different market designs for trading. There are significant differences among the different stock markets, from discrete or call auctions, continuous trading with and without market makers or dealers [57, 58, 59], among others. The researchers on financial markets based the comparison on indicators of market efficiency and market liquidity. These concepts permit to describe the functioning and behavior of the different market designs.

One of the main differences between the electricity markets and financial markets is that, in electricity markets, the market closing is the limit for trading for each production hour and there is not more opportunity for trading the same hour after delivery. While in financial markets, non-accepted bids for a particular product can be traded the next days. This aspect impacts the liquidity of the intraday electricity market on the last trading hours before real time. Additionally, forecast of intermittent RES-E improve significantly close to real time. This is especially important in countries with high penetration of intermittent RES-E.

In addition, although electricity is always the same product, each production hour is different as demand and supply change from hour to hour. Another characteristic different from financial market is the existence of negative prices because of inflexibilities of the market.

These differences between electricity as a commodity and stock markets make it difficult to apply those concepts from financial markets to the electricity market. New liquidity measures are needed to analyze market behavior in continuous electricity markets, which do not only depend on simplistic indicators such as trading volumes, but that also consider other dimensions [60][8]. Furthermore, market parties should build bidding strategies in the intraday markets that incorporate prices behavior over time. For this purpose, access to market bid data over time is essential to understand market parties' behavior.

Hagemann and Weber [56] present two models to explain liquidity for the German intraday market. They conclude that trading behavior has a significant influence on liquidity. From the model results, impatient traders match contrary intraday positions within their portfolios before they close the remaining net deviations from the day-ahead planning in the intraday market. The analysis is performed with data from 2010 and 2011, which may significantly change the conclusions from 2012 onwards when RES-E can choose the feed-in premium and manage their own imbalances, as explained below.

2.4.2 Changes in German RES-E support schemes

RES-E in Germany have been supported through feed-in tariffs until 2012. The TSOs were in charge of forecasting all RES-E generation and selling it in the market. Since January 2012, a market premium was introduced as an alternative to the feed-in tariff with EEG amendment [61]. With this change on RES-E remuneration, RES-E can choose to participate directly in the market and bear balancing costs from schedule deviations or continue with the former feed-in tariff.

Table 2.4.3 shows the hourly German wind generation for 2012 and 2013 under feed-

[8] The liquidity concept has been argued to be slippery and elusive, mainly because it includes a number of transactional properties of the market. Kyle [60] defines three dimensions of liquidity: tightness, depth and resiliency. Tightness refers to the cost of turning a position over a short time; it is referred to transaction costs and usually measured with the bid-ask spread. Depth refers to the size that the bid order flow requires to change prices. Resiliency indicates the speed at which prices recover from shocks.

in tariff[9]. The profitable FiP scheme introduced in 2012 has significantly moved wind units from the FiT to the premium option. Gawel and Purkus [61] points out that the FiP scheme represents windfall profits for RES-E units, which incentivizes RES-E to move to the premium scheme. However, this change from FiT to FiP has not substantially increased intraday volumes (as shown in table 2.4.1). This is because the German TSOs were already obliged to manage the RES-E imbalances in the intraday market before 2012.

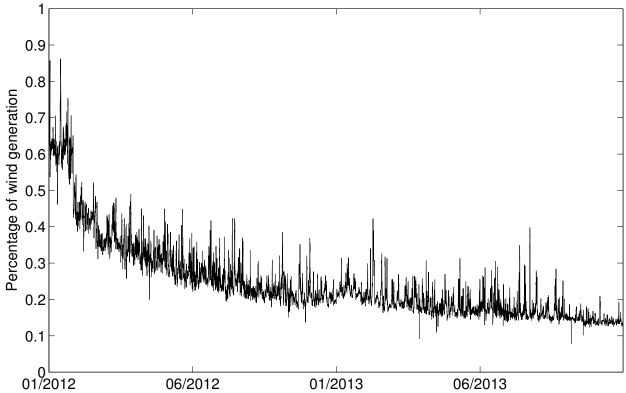


Figure 2.4.3: Hourly wind generation under feed-in tariff for 2012 and 2013

2.4.3 German RES-E balancing

The change in support schemes has also affected the balancing energy used by the German TSOs to manage energy imbalances of RES-E. Figure 2.4.4 shows the probability density estimation for balancing energy used by the German TSOs, using the kernel smoothing function of Matlab Statistical Toolbox. These data correspond to hourly time series for April to October for 2011, 2012 and 2013 (these months were chosen because of equal data availability for the three years). A negative value means a surplus of RES-E, while a positive value means deficit of RES-E. It is remarkable from Figure 2.4.4 that for 2011 the balancing energy used has negative values for around 70% of the hours, while for 2012 and 2013 positive and negative values are almost equally distributed. For 2011, the TSOs had to balance the whole generation coming from RES-E. Figure 2.4.4 shows on average for 2011, German TSOs needed to use systematically more downward regulation than upward regulation (when as expected negative and positive imbalances should be distributed with a mean value close to zero). This also coincide with significant low imbalance prices with respect to day-ahead prices for the year 2011 (Table 2.9). Further research should investigate this finding and analyze in detail the incentives for TSOs when they withhold balance responsibility for RES-E.

[9]Based on the German TSOs platform for renewable data: www.eeg-kwk.net.

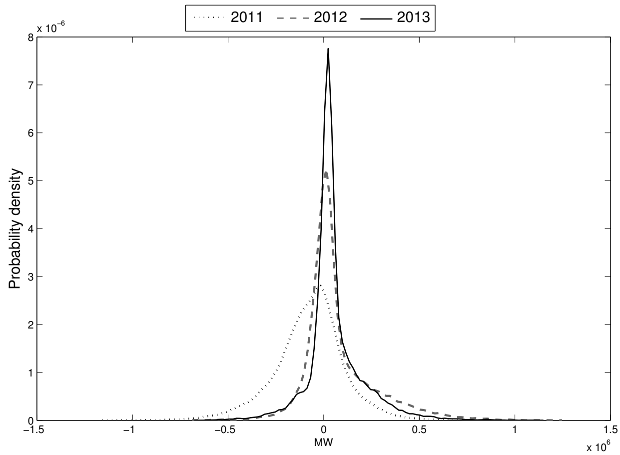


Figure 2.4.4: Probability density estimation for balancing energy used by German TSOs to manage RES-E imbalances

Table 2.9: German average prices (€/MWh)

Prices	**2011**	**2012**	**2013**
Day-ahead	51,18	42,61	37,78
Intraday	50,72	43,59	38,57
Imbalance	32,96	46,42	34,71

2.5 Convergence bidding for European intraday markets

The authors would like to thank the comments from Yannick Perez from Paris Sud University and Sara Lumbreras from Comillas University.

Short-term electricity markets have been restricted to transactions reflecting physical production or consumption of electricity. Some USA markets have implemented financial arbitraging in these markets, starting with PJM market in 2000. This is known as “virtual bidding” or “convergence bidding”[10], which allows financial arbitraging between the day-ahead and real-time markets. The literature has discussed the benefits and potential risks of this policy for the US [62, 63, 64]. In general terms, the evidence points out a positive effect of convergence bidding in terms of economic efficiency in the USA markets.

In Europe, convergence bidding is not allowed in the short-term markets (day-ahead,

[10]This thesis uses the terminology of convergence bidding.

intraday and balancing markets). These markets are only open to market parties that intend to physically produce or consume electricity, or intermediaries that have the same purposes. Given the increasing share of intermittent RES-E in Europe, different market designs need to be more flexible and compatible with variability and limited predictability of intermittent RES-E.

Intraday markets play an important role in managing energy imbalances from intermittent RES-E by decreasing the needs of energy balancing actions taken by the System Operators. However, the development of intraday markets is more recent and generally characterized by low liquidity [19, 40]. The implementation of convergence bidding can potentially improve liquidity in intraday markets, increase economic efficiency and reduce the balancing cost of renewable sources. Additionally, its implementation is compatible with both designs of intraday markets currently in place in Europe. To the authors' knowledge, the convergence bidding theory has not been explored earlier by literature to the European context.

This section is organized as follows: Section 2.5.1 describes the convergence bidding and past experiences in the US markets. Section 2.5.2 describes the organization of short-term electricity markets in Europe, with a main focus on intraday markets and their current state. Section 2.5.3 explores if it is economically attractive for market parties the implementation of convergence bidding in the German and Spanish markets, based on the risk premium between day-ahead and intraday prices. Section 2.5.2 discusses the potential benefits of convergence bidding in Europe.

2.5.1 Convergence bidding: theory and implementation in the USA markets

In contrast with most commodity markets open to financial trading, traders that participate in electricity short-term markets traditionally have to possess the means to produce the traded commodity (i.e. possess electricity generation units), to consume electricity or to be an intermediary that sells or buys energy with physical implications. However, this aspect has changed in some of the US electricity markets. Some US short-term electricity markets have allowed the possibility for traders who do not intend to produce or consume energy to participate in these markets. This has led to a new form of bidding practices in these markets known as "convergence bidding." Convergence bids are financial transactions that do not affect real-time production or consumption of electricity. This mechanism allows arbitraging between market price differences (in the US, between the day-ahead and real time markets). Convergence bidding tends to balance out prices from the day-ahead and real time markets.

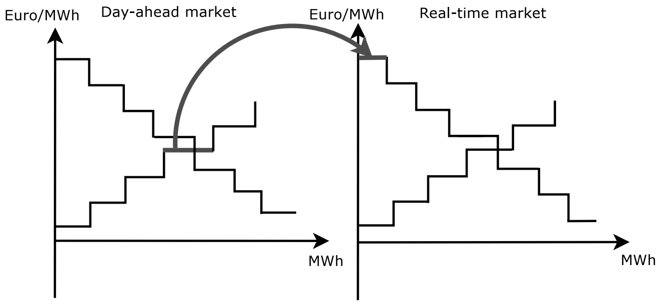
2.5.1.1 Definition

Under the US convergence bidding design, the Independent System Operators (ISO) can distinguish convergence bids from others, so these bids do not affect physical flows[11]. Although price arbitrage between the markets is also possible with physical arbitrage, this option restricts arbitrage to physical players that might not exploit all the arbitrage opportunities [62], given that this is not a part of their financial activities.

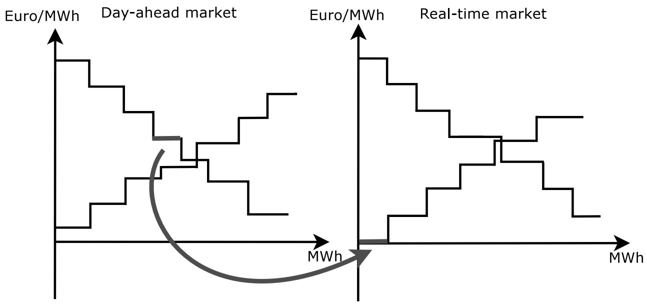
Another possibility of arbitrage is implicit convergence bidding, which consists on deviating from energy previously traded in the day-ahead market and pay the corresponding imbalance price. However, this option can endanger the system reliability if the imbalance prices do not reflect the costs of procurement balancing services. This problem was present in the California electricity market crisis on 2000-2001 [62].

Convergence bids in the USA design are placed only in the day-ahead market, with positions being automatically reversed in the real time market. Bids in the real time market are set as price takers (see Figure 2.5.1). A matched convergence supply or increment convergence offer (also known as "incs") creates a financial obligation to buy back the bid quantity in real-time for the same location and hour (Figure 2.5.1a). Convergence supply bids are set in the real-time market at the maximum price allowed in this market. A matched convergence demand or decremental convergence bid (also known as "decs") creates an obligation to sell the bid quantity in real-time (Figure 2.5.1b). The convergence demand in the real-time market is set at zero or minimum allowed price. The convergence supply bids decrease day-ahead prices and increase real-time prices, whereas the converge demand bids increase the day-ahead prices and decrease the real-time prices. The payoff that convergence bidders receive is the price difference between the market prices (day-ahead and the real-time) times the quantity matched.

[11] Indirectly, convergence bids can affect the dispatch of generators. For example, a convergence increment or supply bid could displace a generator in the day-ahead market with a long start-up period which can be unfeasible to dispatch in real-time [63].



(a) Convergence Supply Bid



(b) Convergence Demand Bid

Figure 2.5.1: Convergence bidding mechanism

The literature has identified different benefits in the US markets where convergence bidding have been implemented:

- Convergence bidding is based on price arbitrage between short-term markets, which decreases market price differences. This price convergence may lead to a self-schedule of market parties [62].
- If the market is open to financial traders, they would enter into the market to profit from the price differences, until expected profits are reduced to zero (considering the transaction costs). This increases the liquidity in the market as more transactions occur. The opening of the arbitrage market to financial traders reduces the expected profits of arbitrage and improves market efficiency. As shown by Ledgerwood and Pfeifenberger [65], there is an optimal arbitrage for a single trader who will not exploit all arbitrage opportunities.
- Convergence bidding can decrease the market power of physical players [66]. As “convergence” competition is introduced to the market, if prices are artificially high in one market, convergence bids can decrease them.
- Hedging opportunities increase for generators and loads, as they can limit their exposure to real-time market or imbalance penalties. Potential beneficiaries

are intermittent units such as wind [66] and small players that cannot use generation portfolio to balance power deviations.

- A decrease of price risk, resulting from the decrease of price volatility and price differences, can increase market efficiency and benefit all players [64, 63]. Saravia [67] argues that by bearing some risk in the market speculators decrease the risk premium, measured as the price difference.
- Another potential benefit of convergence bidding is the reduction of total costs for consumers if day-ahead prices decrease, as most of the energy is traded in this market [67].

2.5.1.2 USA experiences with convergence bidding

Different USA electricity markets have allowed convergence bids in the day-ahead and real time markets, such as: PJM since June 2000; New York ISO (NYISO) since November 2001; New England ISO (ISO-NE) since March 2003; Midwest ISO (MISO) since April 2005 and the California System Operator (CAISO) starting from February 2011. Except for California, convergence bidding is known as virtual bidding in the rest of the US markets.

Significant participation and price convergence between the day-ahead and real-time prices have resulted from the implementation of convergence bidding in these markets [68, 64, 67]. Celebi et al. [63] showed that price volatility in CAISO (before the implementation of convergence bidding) was much higher than eastern ISOs. Saravia [67] found a decrease of market prices from exporting zones after the implementation of convergence bidding in the New York market.

2.5.1.3 Possible risks of convergence bidding identified in the USA markets

Celebi et al. [63], Ledgerwood and Pfeifenberger [65] signal some potential misuse of convergence bidding to manipulate the Financial Transmission Rights (FTRs). This strategy is executed by incurring in losses with convergence trading (and therefore create an economic inefficiency) to alter the locational price signals. Then, financial losses are recovered with FTRs revenues. Midwest ISO and PJM have investigated cases of misusing of convergence bidding. However, financial losses using convergence bidding do not automatically mean manipulation and it needs further investigation [65]. The USA markets have set rules to avoid manipulations of convergence bids and revenues from FTRs; however, those rules do not completely avoid potential manipulations [63]. Celebi et al. [63] also argues that Regional Transmission Organization (RTO) can solve loop flows in real-time, and then bidders can submit a convergence purchase in day-ahead, which can worsen the problem. This localized congestion can impose high costs to loads or generators in remote or small parts of the network.

In the Californian case, convergence bidding has shorter implementation time in comparison with the other markets. CAISO [69] has argued that the convergence bidding did not improve market prices convergence. Extremely high real-time prices occurred in the California market mainly because of shortages of ramping capacity. Convergence bidding has added capacity but it was not enough to solve the limitations; therefore, high convergence demand has taken advantage of high real-time prices. In California, operational and software improvements have been recommended to improve price convergence as well as a better modeling of transmission at the day-ahead level [70]. Consequently, these previous flaws might be the cause of price divergence instead of the convergence bidding policy alone.

This possible manipulation of FTR is not considered a major risk for European markets because transmission capacity is managed differently, as explained in the following section.

2.5.2 European market design

This section discusses the main designs that can be relevant for a future implementation of convergence bidding policy in Europe. In the short-term, the European electricity markets are organized as a sequence of markets, where the day-ahead market plays an important role in terms of trading volumes. European day-ahead markets are usually characterized by a single national price[12], in contrast to the USA markets which use nodal pricing and FTR. After the day-ahead market, and considering bilateral trading, a congestion management mechanism takes place to solve foreseen congestions. Then, intraday markets take place after the day-ahead market until close to real time, and give the possibility to update the energy schedules. Additionally, SOs manage the active power balance through the balancing markets. In the balancing markets, the SOs are the single buyers of reserves from qualified market participants. In Europe, the short-term electricity markets (day-ahead, intraday and balancing) are markets restricted by regulations for physical delivery [19]. They are open only to agents that consume and produce electricity or traders who buy or sell electricity for third parties. Therefore, pure financial arbitrage between markets is not allowed.

There are additional design differences between US and the European electricity markets. In US electricity markets (PJM, New England, New York, Midwest, California and Texas), the ISOs or RTOs manage the day-ahead, real-time and ancillary service markets. Market clearing incorporates network constraints and prices are computed at a nodal level. This has the advantage for managing simultaneously the market pool and the system security and reliability. In the discussed US markets, the real time markets are cleared 5 minutes before real-time that allows modifying schedules very close to the operational hour.

[12] In the Nordic region and Italy, there are zonal price areas, which consist in dividing the countries in different predefined zones in case of congestions.

The European day-ahead and intraday markets are managed by power exchanges, which are different institutions from SOs. After these markets are cleared by the power exchanges, the SO solves system and reliability constraints. Furthermore, the SO buys balancing services in the balancing markets for both capacity and energy components. Further description of balancing market designs can be found in Chapter 4.

The main European institutions that regulate the electricity sector have been working in achieving an Internal Electricity Market (IEM), pushed by the European Commission [12]. Under IEM, convergence bidding might have an interesting application, allowing financial traders to arbitrate between the spot markets with the expected benefits discussed earlier.

2.5.2.1 Current organization of the European intraday markets

The European intraday markets generally have a reduced history than day-ahead markets. A detailed discussion of the developments of these markets is found in Section 2.2. In Europe, there are 15 with intraday markets [40]. From the countries with intraday markets, the trading volumes are low in comparison with the day-ahead market. In terms of electricity consumption, based on 2010 and 2011 data, the intraday markets represent less than 1%, except for the Spanish market [40].

EWEA [40] points out that low liquidity in the intraday markets leads to use more expensive sources in real-time. In addition, the markets with low trade activity often have less transparent prices, with high impact of individual players on price formation.

Ofgem, the Great Britain regulator, has been concerned about liquidity in the market. Ofgem argues that participation of financial trading increases trading volumes and provides innovative solutions to small players to access the market [71]. However, the focus of Ofgem has been mainly long-term electricity markets instead of short-term markets, as volumes on short-term markets are growing, but they are relatively low in comparison to other European markets.

2.5.2.2 Liquidity providers in the European intraday markets

In order to increase liquidity in intraday markets, some European markets use the figure of liquidity providers or market makers, specifically in the Nordic intraday market (Elbas) and the Belgium Belpex Continuous Intraday Market (Belpex CIM). Both Elbas and Belpex CIM present low trading volumes [40]. In these markets, there are only a few market makers and the flexibility they provide is very limited in comparison with convergence bidding.

Under the current settlements, there is not price arbitrage between different markets such as the convergence bidding applied in US markets. The market makers are physical players that set quotes only in the intraday market (buy cheap and sell more expensive). If liquidity providers cannot revert their positions with market bids from other parties, they have to deliver or reduce the contracted energy with their own units. In both cases (Nord Pool and Belpex) the market makers are big companies that have a large portfolio and can bear liquidity risks.

In the Nordic Region, market makers are obliged to quote bids at predefined quantities and spreads, depending on the Elspot prices [72]. By October 2013, there were three market makers on Elbas market: two in Sweden and one in Finland. These companies have a significant share in their countries and regions where they participate. In return for becoming a market maker, Nord Pool offered reduced fees for participating in the market [72].

Belpex sets the agreement conditions to become a market maker in the Belpex CIM [73], which consists in the submission of orders at predefined prices. These prices are related to the day-ahead prices or to a marginal cost formula. Currently, there is only one market maker in Belpex CIM, EDF Luminus [73], which is a subsidiary of EDF and the second largest electricity producer in the Belgian market.

After this review of the organization of EU intraday markets and actors providing liquidity in these markets, the following section shows the attractiveness of convergence bidding in Spain and Germany, two EU leaders in terms of renewables energy penetration in electricity markets.

2.5.3 Attractiveness of convergence bidding in the German and Spanish intraday markets

This section assesses whether the implementation for convergence bidding between day-ahead and intraday markets is profitable. In order to assess this, the premium between day-ahead and intraday prices is checked to determine the statistical significance and if the day-ahead prices are unbiased predictors of the intraday prices. Section 2.5.3.1 defines the risk premium and the empirical model used to measure it. This empirical model is applied in Sections 2.5.3.2 and 2.5.3.3 to test if there are arbitrage possibilities between the day-ahead and intraday markets in the Spanish and German markets.

2.5.3.1 Market efficiency and risk premium

The risk premium is the difference between the forward prices (day-ahead) minus the spot prices (represented by the intraday prices). Most of the studies that analyze the risk premium use the ex-post risk premium to avoid unrealistic assumptions about expected spot prices. As discussed by Haugom and Ullrich [51], the ex-post risk premium can be decomposed as the ex-ante risk premium plus the forecast error. However, it is usually assumed in the literature that the ex-post risk premium is a good proxy of the ex-ante premium.

For both German and Spanish cases, the realized risk premium is defined in (2.5.1).

$$RP_t = P^D_{h,t+1} - P^I_{h,t} \tag{2.5.1}$$

Where $P^D_{h,t+1}$ is the day-ahead price for the hour (h) of the next day (t+1). $P^I_{h,t}$ is the volume-weighted average intraday price for the hour (h) of the current day (t), although some of the trade can occur the day before.

Fama [74] introduces the Efficient Market Hypothesis, which in general terms signals that financial prices should fully reflect all available information. In its strong from, it means that a market is efficient if it is not possible to make economic profits by trading on the basis of known information. As it is practically impossible to verify market efficiency based on all available information for market parties, researchers use the weak form or semi-strong-form efficiency [51].

Under the hypothesis of market efficiency in its weak form, forward prices should be an unbiased forecast of future spot prices [51]. This can be empirically tested under the null hypothesis that forward prices are unbiased forecasts of future prices, which means $\alpha = 0$ and $\beta = 1$ as defined in (2.5.2), where $\varepsilon_{h,t}$ follows a white noise process. Spot prices are represented by the intraday prices and forward prices by the day-ahead prices. Evidence of α systematically different from zero indicates that a risk premium is present.

$$P^I_{h,t+1} = \alpha + \beta P^D_{h,t} + \varepsilon_{h,t} \tag{2.5.2}$$

As electricity prices present extreme distribution properties, the estimation considered the use of logarithms (2.5.3). In the German case, intraday prices can have negative values; therefore, a constant is introduced before applying the logarithms.

$$ln\left(P^I_{h,t+1}\right) = \alpha + \beta ln\left(P^D_{h,t}\right) + \varepsilon_{h,t} \tag{2.5.3}$$

The next subsections analyze if there is a significant day-ahead premium in the German and Spanish markets from 2011 to September 2013. By analyzing the day-ahead premia, it can be determined whether there is an opportunity for price arbitrage between the markets and whether there is room for the convergence bidding policy.

2.5.3.2 Application to the Spanish market

The Iberian power exchange (OMIE) operates the day-ahead and intraday electricity markets for Spain and Portugal. In case of transmission congestions between both countries, a market splitting mechanism is used. The Iberian day-ahead market takes place at 12h00[13] of the day before (d-1) and at 14h00 (d-1) the final program is obtained considering the technical restrictions and reliability of the system.

The Spanish intraday market has different sessions with different trading volumes. Consequently, in order to have a representative price per hour the volume-weighted average price has been computed. The volumes traded per session are used for this purpose. The data are publicly available in Red Eléctrica de España.

Table 2.10 shows the hourly Spanish day-ahead premia, as defined in (2.5.1). The sample period is from January 2011 to September 2013, in total 24096 observations. The peak-hours are those for weekdays between 8h00 to 22h00, the rest of the hours are considered as off-peak. The seasons are defined as: Winter: from January 1st until March 31st; Spring, Summer, and Fall are defined by subsequent three month periods, respectively. In most of the seasons, the premia are positive and statistical significant throughout the analyzed period (day-ahead prices are higher than intraday prices). There are seasonal patterns that differ between the years. The price data present non-symmetric and leptokurtic distributions, therefore the logarithms are used to test the existence of forward premium.

[13]Before October 15th 2013, the gate closure time was 10h00 and the first session of the intraday market was delayed one hour.

Table 2.10: Spanish average day-ahead premia from 2011 to September 2013

	2011			2012			2013		
	Day	**Peak**	**Off-Peak**	**Day**	**Peak**	**Off-Peak**	**Day**	**Peak**	**Off-Peak**
Overall									
Premia	1.47***	1.65***	1.32***	1.13***	1.34***	1.17***	0.95***	1.54***	0.46*
Std.Dev.	4.33	3.85	4.68	4.43	3.99	4.74	5.68	5.27	5.95
Skewness	0.84	2.54	0.10	0.31	0.57	0.21	0.09	0.75	-0.22
Kurtosis	12.67	20.70	8.99	5.07	5.42	4.72	7.20	7.58	6.74
Winter									
Premia	1.60***	2.16***	1.14***	0.72**	1.24***	0.31*	1.19***	2.29***	0.30*
Std.Dev.	4.73	4.01	5.20	4.29	3.77	4.63	6.00	6.57	6.49
Skewness	1.10	3.61	0.25	0.24	0.28	0.31	0.26	0.51	0.06
Kurtosis	15.95	32.36	9.87	5.82	6.37	5.48	6.84	6.82	6.93
Spring									
-1remia	P.75**	0.70**	0.79**	1.54***	1.33***	1.72***	1.42***	2.05***	0.91***
Std.Dev.	3.64	2.50	4.35	4.5735	4.31	4.77	5.75	4.59	6.50
Skewness	-1.12	0.81	-1.33	0.2733	0.77	-0.04	-0.40	0.64	-0.57
Kurtosis	14.35	9.13	11.99	4.5307	5.05	4.28	6.35	5.36	5.66
Summer									
Premia	1.48***	1.33***	1.60***	1.35***	1.33***	1.36***	0.24*	0.32*	0.17
Std.Dev.	3.85	3.60	4.03	3.86	3.37	4.21	4.44	4.16	4.66
Skewness	1.64	3.08	0.81	t.73	0.67	0.73	0.19	0.87	-0.19
Kurtosis	11.61	22.79	5.95	5.80	6.27	5.30	6.99	6.95	6.85
Fall									
Premia	2.04***	2.41***	1.74***	0.89***	1.45***	0.44*	-	-	-
Std.Dev.	4.88	4.71	4.99	4.87	4.43	5.16	-	-	-
Skewness	0.83	1.40	0.49	0.19	0.02*	0.11	-	-	-
Kurtosis	7.64	9.-2	6.15	4.37	4.32	4.23	-	-	-

*Significant at 90%; *Significant at 95%; ***Significant at 99%

The t-Statistics are based on the hetroskedasticity and autocorrelation consistent covariance matrix estimator.

Table (2.11) shows the test for the unbiased forward hypothesis in the Spanish market. The results are different for the considered years. During 2011, there is evidence of systematic risk premia ($\alpha \neq 0$) but limited evidence of biased predictions ($\beta \neq 1$). During 2012, the results show a systematic risk premia and evidence of biased prediction. For 2013, there is limited evidence of systematic risk premia and biased predictions.

Table 2.11: Test for unbiased Spanish forward hypothesis

	2011			2012			2013		
	Day	**Peak**	**Off-Peak**	**Day**	**Peak**	**Off-Peak**	**Day**	**Peak**	**Off-Peak**
Overall									
α	0.03***	0.01	0.04***	0.10***	0.06***	0.3***	0.01	0.01	0.01
β	0.99	0.99	0.98*	P.97**	0.98*	0.96***	0.99	0.99	0.99
R^2	0.97	0.97	0.97	0.97	0.98	0.97	0.99	0.99	0.99
Winter									
α	0.03***	0.44***	0.03*	0.37***	0.33***	0.05**	0.01*	0.02**	0.01
β	0.98*	0.88***	0.99	0.90***	0.91***	0.99	0.99	P.98*	0.99
R^2	0.98	0.95	0.98	0.96	0.92	0.97	0.99	0.99	0.99
Spring									
α	0.58***	0.01	0.95***	0.07***	0.02	0.12***	.01*	H.01	0.01
β	0.85***	0.99	0.75***	0.98*	0.99	0.96***	0.98*	0.99	0.98*
R^2	0.93	0.97	0.86	0.97	0.98	0.96	0.99	0.99	0.99
Summer									
α	-0.10***	-0.05	-0.11*	0.49***	0.33***	0.62***	-0.04*	-0.53***	0.41***
β	C.02*	1.01	1.02*	0.87***	0.91***	0.83***	1.01	1.13***	0.89***
R^2	0.86	0.89	0.80	0.93	0.95	0.92	0.94	0.94	S.92
Fall									
α	0.02*	-0.2	0.03**	0.14***	0.08***	0.19***	-	-	-
β	0.99	0.99	0.98*	0.96***	0.97**	0.95***	-	-	-
R^2	0.98	0.97	0.98	0.98	0.98	0.95	-	-	-

H0: $\alpha = 0$, and $\beta = 1$.

*Significant at 90%; *Significant at 95%; ***Significant at 99%

As shown in Tables 2.10 and 2.11, the day-ahead premia are positive and statistically significant for most of the hours of the years 2011 and 2012. The average day-ahead premium for both years is 1.30 €$/MWh$. During 2013, the risk premia decreased, but it is still present. This significant premia might be attractive for the implementation of convergence bidding as it is higher than the premia presented in US markets. For instance, the PJM forward risk premium has decreased considerably since the implementation of convergence bidding [75, 51]. In 2000, the average market premium was 1.61 $\$/MWh$ [76]. Longstaff and Wang [75] found a mean ex-post risk premium of 0.59 $\$/MWh$ for the time period of 2 years and two months after the implementation of convergence bidding in PJM. For a 10 years period, Haugom and Ullrich [51] found that the risk premium had decreased to 0.29 $\$/MWh$. They interpret this as a signal that the market has matured. Some other studies on other USA markets do not find strong conclusions on price convergence [77, 78, 79, 80]; however, they have considered shorter time series after the implementation of convergence bidding.

As explained in Section 2.3, renewable sources were having profits from arbitraging between the day-ahead and intraday markets, with additional costs for the system. Convergence bidding would have prevented this to happen, encouraging these sources to bid closer to the expected energy.

2.5.3.3 Application to the German market

Table 2.12 shows the day-ahead premia for the period from 2011 to September 2013, with a total 24096 observations. The seasonal periods correspond to the same ones applied in the Spanish case. The price data present non-symmetric and leptokurtic distributions which change between seasons and years. In the German market, there is not a clear trend in the day-ahead premium. It seems slightly positive in 2011 and negative in 2012 and 2013. These changes might be due to the modifications made to the RES-E support schemes in Germany. The premia also present significant seasonal patterns.

Table 2.12: German day-ahead premia from 2011 to September 2013

	2011			**2012**			**2013**		
	Day	**Peak**	**Off-Peak**	**Day**	**Peak**	**Off-Peak**	**Day**	**Peak**	**Off-Peak**
Overall									
Premia	0.46*	0.44*	0.48*	-0. fore	-1.48***	-0.66**	-0.71**	-0.67**	-0.73**
Std.Dev.	8.53	8.54	8.52	,.64	10.56	8.99	8.48	9.96	7.40
Skewness	1.28	0.33	1.88	-2.41	-3.02	-1.71	-1.42	-0.65	-2.49
Kurtosis	20.99	10.28	27.78	i.89	38.16	37.37	16.32	8.23	28.90
Winter									
Premia	0.92***	1.08***	0.82**	-0.51*	-1.74***	0.26*	0.10	0.50**	-0.15
Std.Dev.	10.13	9.69	10. 1	12.51	15.06	10.52	7.99	9.69	6.70
Skewness	2.42	1.00	3.16	-2.11	-2.85	-0.27	-0.27	-0.37	-0.17
Kurtosis	33.05	16.31	40.99	27.33	26.Du	15.93	6.57	5.96	5.40
Spring									
Premia	-0.27*	-0.57**	-0.08	-1.84***	-2.22***	-1.59***	-1.93***	-1.71***	-2.07***
Std.Dev.	7.26	7.54	7.07	7.93	8.58	7.48	9.94	10.92	9.28
Skewness	0.02	-0.13	0.14	-0.52	-0.38	-0.61	-1.97	-0.60	-3.36
Kurtosis	4.09	3.93	4.17	4.18	3.51	4.75	17.31	5.08	30.99
Summer									
Premia	1.27***	1.87***	0.89***	0.39*	0.14	0.55**	-0.28*	-0.76**	0.02
Std.Dev.	7.57	7.68	7.49	6.00	6.56	5.60	7.14	9.08	5.55
Skewness	0.54	0.87	0.32	-0.25	-0.56	0.11	-1.03	-0.99	-0.55
Kurtosis	5.68	6.43	5.07	4.19	4.65	3.,	18.32	16.78	4.79
Fall									
Premia	-0.06	-0.6**	0.29*	-1.96***	-2.11***	-1.86***	-	-	-
Std.Dev.	8.78	8.82	8.73	10.62	10.05	10.98			
Skewness	0.59	-0.62	1.36	-3.40	-3.80	-3.20			
Kurtosis	10.93	5.31	14.30	50.27	48.06	50.77			

*Significant at 90%; *Significant at 95%; ***Significant at 99%

The t-Statistics are based on the hetroskedasticity and autocorrelation consistent covariance matrix estimator.

Table 2.13 show systematic risk premia ($\alpha \neq 0$) and evidence of biased prediction ($\beta \neq 1$) for the German case for the whole analyzed period, which suggests that there is room for financial arbitraging between day-ahead and intraday markets.

Table 2.13: Test for unbiased German forward hypothesis

	2011			2012			2013		
	Day	Peak	Off-Peak	Day	Peak	Off-Peak	Day	Peak	Off-Peak
Overall									
α	1.38***	1.88***	1.45***	1.18***	1.29***	1.29***	0.78***	0.89***	0.87***
β	0.74***	0.65***	0.72***	0.79***	0.76***	0.77***	0.84***	0.82***	0.82***
R^2	0.85	0.75	0.86	0.92	0.83	0.94	0.83	0.81	0.81
Winter									
α	1.61***	2.36***	1.70***	1.67***	1.70***	1.92***	0.79***	1.10***	0.83***
β	0.70***	0.56***	0.68***	0.71***	0.70***	0.67***	0.84***	0.78***	0.83***
R^2	0.91	0.72	0.93	0.83	84	0.77	0.84	0.82	0.82
Spring									
α	1.52***	1.85***	1.69***	1.47***	1.54***	1.54***	0.95***	.95***	1.05***
β	0.71***	0.75***	0.68***	0.74***	0.73***	0.73***	0.80***	0.81***	0.78***
R^2	0.78	0.78	t.75	0.76	0.77	0.72	0.78	0.74	0.79
Summer									
α	1.29***	2.03***	1.26***	1.17***	1.39***	1.13***	0.95***	1.09***	1.01***
β	0.75***	0.Te***	0.76***	0.80***	0.76***	0.80***	0.81***	0.78***	0.80***
R^2	0.76	0.72	0.75	0.82	0.83	0.79	0.83	0.82	0.80
Fall									
α	1.23***	1.59***	1.36***	0.70***	0.80***	0.97***	-	-	-
β	0.77***	0.70***	0.74***	0.88***	0.86***	0.83***	-	-	-
R^2	0.81	0.74	0.79	0.97	0.83	0.98	-	-	-

H0: $\alpha = 0$, and $\beta = 1$.

*Significant at 90%; *Significant at 95%; ***Significant at 99%

2.5.4 Potential benefits and implementation concerns of convergence bidding in Europe

The literature has pointed out potential benefits of convergence bidding in the US. In the European context, those benefits are also expected to happen. Section 2.5.3 shows that there is potential for convergence bidding in two relevant European markets. In Europe, there are concerns about liquidity in intraday markets [19, 40]. Weber [19] discusses potential actions to increase liquidity in the European intraday markets. One of the recommendations given is to move to a discrete auction scheme because of the high volumes of energy traded in the Spanish intraday market. This option is also supported by Borggrefe and Neuhoff [9]. However, the introduction of a discrete market would not be automatically translated into higher trading volumes. The high trading volumes in the Spanish intraday market might be due to the other regulations present in this market (as explained in Section 2.3). In addition, the obligation for market parties to bid in the markets does not necessarily increase liquidity as there are other dimensions of liquidity, and those market parties that have a portfolio of units can develop portfolio balancing through the market.

Based on the model results, convergence bidding can be a successful policy to increase liquidity in the intraday market. Furthermore, market efficiency can be improved by allowing convergence bidding. In the Spanish case, due to the lower intraday prices, price arbitrage by physical units has occurred but they are not fully exploited. With the implementation of convergence bidding, the threat of financial arbitraging would decrease the incentives for physical players to schedule differently from marginal costs or expected energy in order to take advantage of price differences.

Higher trading volumes in the intraday market due to the implementation of convergence bidding potentially contribute to balance intermittent RES-E, decrease balancing costs and reduce the need of balancing actions carried by SOs.

There could be some practical issues which differentiate convergence bidding implementation in the European context with respect to the US design. In the US, convergence bids are price takers in the real-time market. The US real time markets follow the marginal pricing rule. With continuous trading (as implemented in Germany and most of the European intraday markets), the price taker concept cannot be applied as prices are set differently (as explained in Section 2.2). In addition, in case that there is not enough liquidity, the convergence bids might not find a counterpart in a specific hour. One possible solution to overcome this issue is to lead freely convergence bidders to set prices in the intraday market, and if they cannot succeed on matching the convergence bids, they would face the corresponding imbalance price. Although convergence bidders might not find a counterpart in the intraday market, they might be interested to end up with an imbalance if a single imbalance pricing is applied (for further discussion on imbalance pricing see Chapter 7).

2.6 Conclusions on European intraday markets

After the day-ahead market, the intraday markets provide trading possibilities to market parties to balance their positions without the intervention of the system operator. Therefore, the more the market parties can balance through the intraday markets, the less balancing actions are needed to be taken by the system operator to balance the system.

In Europe there are two intraday market designs: the discrete auction (applied in Spain) and continuous trading (applied in Germany). The Spanish intraday market has been pointed out by the literature as a good design that provides high liquidity. However, this chapter shows that this is not the case because of the discrete auction design by itself but also by other different market regulations. Some of these market regulations are the dual imbalance pricing mechanism (that strongly penalized the energy imbalances), the allocation of balance responsibility to all market parties (including all the renewable sources), and the unit scheduling instead of the portfolio balancing.

This chapter, in comparison to existing literature, shows that the Spanish intraday market has favored the balancing of renewable sources. However, the Spanish intraday market presents some distortions as a result of market regulations and the interrelation with other short-term markets. In a sequential market organization, distortions in one market can affect the rest. For example, the priority dispatch of national coal units and the compensations from the technical restriction mechanisms allow these units to bid at lower prices in the intraday sessions. The same happens with the additional market for upward regulation in which the selected bids receive remuneration to start-up units, which were not dispatch in the day-ahead market. These regulations have resulted in statistically lower intraday prices with respect to the day-ahead market.

The literature mainly argues that the allocation of balance responsibility should be assigned to all market parties, including intermittent energy sources. This provides an incentive to those generators to improve energy forecasts, which otherwise would be a full responsibility of system operator. However, market parties react to economic incentives to maximize their profits, which depend on market prices, market regulations and support schemes. This may lead to bidding behavior that does not correspond to the expected energy, which eventually may jeopardize the potential benefits of allocation of balance responsibility to all parties. Therefore, the system operator should consider the economic incentives of market parties that affect the market results and should count also on its own centralized generation and consumption forecasts in order to perform contingency analyses and evaluate reserves needs.

The continuous trading differs significantly from discrete auction design. In the continuous trading, pricing of cross-border transmission capacity in case of congestions is not straightforward to compute. In this respect, general principles are proposed to be considered when designing cross-border transmission capacity. However, a detailed analysis on price dynamics needs to be considered.

Changes on support schemes have an important impact on the incentives to market parties to trade in the intraday market. By analyzing data from the Spanish market, the change from feed-in premium to feed-in tariff has decreased substantially the participation in the intraday market. With the feed-in premium scheme, market parties were incentivized to arbitrate between the markets. This has increased reserve requirements and system costs.

In Germany, with the change from feed-in tariff to feed-in premium, the use of balancing energy by the system operators has changed from having a clearly biased strategy before the introduction of the premium option.

Convergence biding policy applied in US markets has been a successful policy to lead to price convergence between short-term markets, increasing liquidity and economic efficiency. The implementation of convergence bidding in Europe has not been explored by the literature earlier. Although the European electricity market designs differ from those of the USA, the implementation of convergence bidding can be beneficial in terms of market efficiency and to increase balancing alternatives of intermittent RES-E. Based on the analysis of prices data from the Spanish and German markets, convergence bidding is an attractive policy to implement in these markets. Practical implementation of convergence bidding should be considered in further steps, as well a possible extension to other markets such as the balancing markets.

Chapter 3

Impact of electricity cross-border intraday trading on wind balancing

This chapter is based on the work described in Chaves-Ávila et al. [81].

3.1 Introduction

Wind Power Producers (WPPs) may participate in short-term market arrangements, but due to uncertainties about energy forecasts, bidding strategies might increase profits of energy traded. These bidding strategies have been widely discussed in the literature. However, the approaches differ according to the markets considered and their characteristics, the methodology and assumptions on market behavior, among other issues. Some of those differences are:

- With respect to the market considered, some papers only have focused on optimal bidding in the day-ahead market: Gibescu et al. [82], Matevosyan and Soder [83]. Morales et al. [84], Usaola and Angarita [85], Usaola and Moreno [86] considered the intraday market for the Spanish case. Bourry et al. [87], Linnet [88] studied the Danish case that is part of NordPool intraday market (Elbas) and has continuous trading each hour. Botterud et al. [89] considered the day-ahead market and real-time market (every five minutes) for the Illinois hub of the Midwest ISO in the US.
- Regarding the methodology, a stochastic linear programming that represents uncertainty with a finite number of scenarios has been used: a mixed inte-

ger formulation with a deterministic characterization of imbalance prices [83], and a linear stochastic optimization formulation with time series uncertainty modeling for all market prices and wind power [84]. A stochastic optimization with probability density functions has been used to describe price uncertainty: using a quantile regression [82, 88], without uncertainty modeling for intraday prices [85], which was introduced on a future work [86] and uncertainty characterization in both intraday and imbalance prices using a time series modeling [90].

- The consulted papers assume that prices for the different markets and wind generation are uncorrelated; WPPs do not affect the market price and the optimal bids are computed only on quantities. Botterud et al. [89], Bueno et al. [90], Morales et al. [84] incorporate risk considerations when computing bidding strategies.

In the Netherlands, some papers have studied the participation of WPPs in the day-ahead market [82]. However, intraday trading possibilities in the Netherlands have not been studied yet, neither cross-border considerations. Furthermore, from the cited studies only Botterud et al. [89] considered that WPPs can generate less than possible power, in cases of negative locational prices and high wind penetration, as included in this chapter.

This chapter proposes a stochastic optimization model for a real case study of a Dutch WPP. The WPP's objective is to reduce its imbalance costs through possible participation in the Dutch day-ahead market, the German intraday market and real-time production adjustment. The model proposed tests the profitability of different strategies and it also gives some insights about the integration of intraday markets in order to facilitate the integration of intermittent RES-E, such as wind.

This chapter continues as follows: a brief description of the Dutch and German electricity market rules is provided in Section 3.2. The mathematical formulation of the model that describes the bidding strategies is presented in Section 3.3.1. Section 3.4 describes the case study, the modeling of uncertainty and the model results. Finally, Section 3.7 concludes and gives some advice for future work.

3.2 Dutch and German electricity markets

3.2.1 Dutch day-ahead and intraday markets

APX is the voluntary power exchange for the Dutch day-ahead and intraday electricity markets. The gate closure of the day-ahead market is at 12h00. The intraday market gives the opportunity to change the energy schedules up to 90 minutes before real time (in 2013 the intraday market gate closure time was reduced to 5 minutes before real-time). However, the Dutch intraday market, in 2010, was cleared in around 12% of the hours and with average volumes of 20 MW (Figure 3.2.1). Since February 17th 2011, the Dutch intraday market is coupled with the Belgium intraday market with implicit allocation of interconnection capacity. During the first six months of the intraday market coupling, liquidity had increased, with a market clearing results for around 20% of the hours (this value remains until 2013). However, it continues to be illiquid and it is risky to build a strategy based on intraday trade possibilities, as a counterpart-bid might not be matched. From March 14th 2012, the Dutch intraday market is also coupled with the Nordic market through the NorNed interconnector.

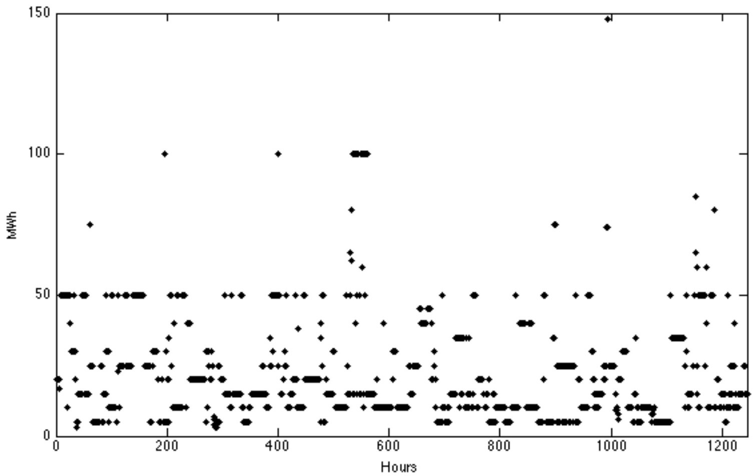


Figure 3.2.1: Volumes of the Dutch intraday market in 2010

The intraday market usually has low liquidity, due to the fact that most generation units prefer to commit their units in advance to consider start-up costs and plan the operation of their units. However, this is not the case for wind power, where more accurate wind energy forecasts are available closer to the operational hour.

3.2.2 The German intraday market

The European Power Exchange (EPEXSPOT) is the market platform for France, Germany and the borders between Germany with Switzerland and Austria. The German intraday market is very liquid, during 2010; it had market-clearing results for almost all the hours (only during 21 hours the market was not cleared). The market is open 24 hours from the day before at 15:00 onwards, and the last trade can be done 45 min before delivery.

The volumes of the German intraday market were very high for 2010 (Figure 3.2.2) in comparison with those of the Dutch market. This is mainly due to the fact that the German TSOs had to manage renewable energy imbalances through intraday market, apart from being a bigger market.

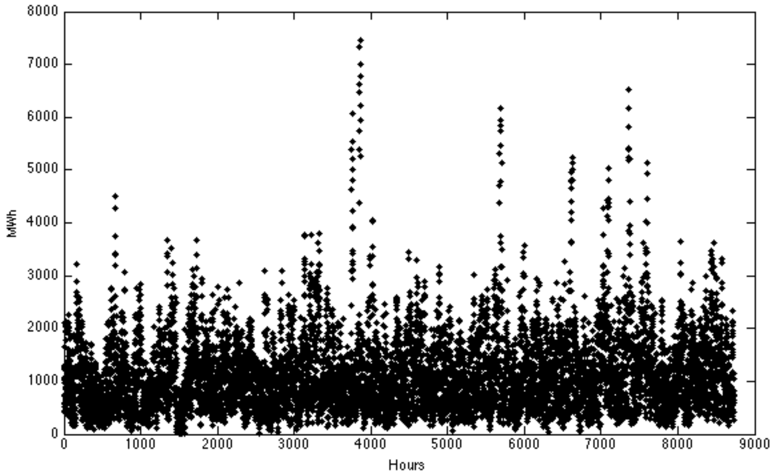


Figure 3.2.2: German intraday market volumes in 2010

The Dutch WPPs might be interested in accessing the German intraday market, as it is liquid. The intraday market allows WPPs to incorporate recent wind energy forecasts, it gives arbitrage opportunities (make profits from price differences from day-ahead, intraday markets and imbalance prices), and the possibility to reduce imbalance volumes and costs associated.

3.2.3 Allocation of transmission capacity between Germany and the Netherlands

Cross-border intraday electricity trading between the Netherlands and Germany is done through an explicit allocation mechanism of transmission capacity that follows the rule “first come, first served”, at zero price. In order to obtain access to transmission capacity, it is required to bid into an intraday capacity platform managed by the TSOs [91]. TenneT (the Dutch TSO) publishes the available intraday transmission capacity at 21h00. The cross-border capacity should be requested at least 75 minutes before real time. The minimum capacity requested should be higher than 1 MW and multiple of 1 MW.

During 2010, in almost all the hours there was interconnection capacity available at the intraday time frame (Figure 3.2.3). In the direction from Germany to the Netherlands, the percentage of hours with available interconnection capacity was 98.3%, and after the nominations have occurred the percentage was 96.7%. On the other hand, the interconnection availability from the Netherlands to Germany was 99.9%, and after nominations 99.5%.

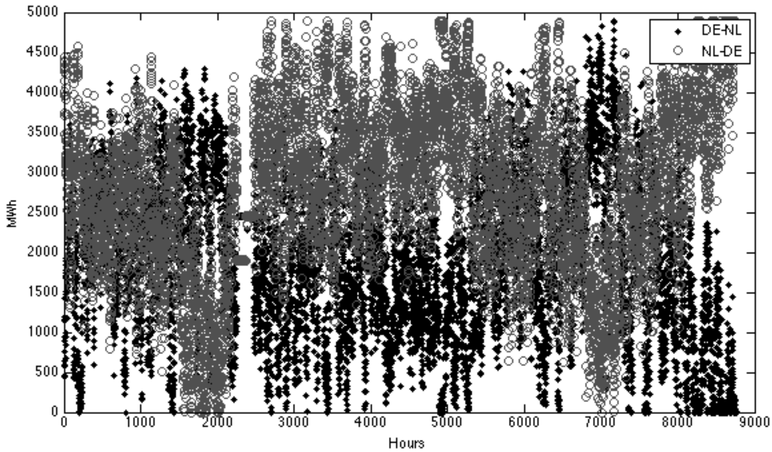


Figure 3.2.3: Available intraday interconnection capacity between Germany and the Netherlands in 2010

The current allocation mechanism of intraday interconnection capacity between Germany and the Netherlands "first come, first served" has been considered discriminatory and non-market based [92]. A cross-border intraday market in the CWE region with continuous trading and implicit allocation of interconnection capacity is expected to increase liquidity and provide more efficient use of interconnection capacity [6].

3.3 Dutch balancing rules

As already stated, electricity markets have the distinctive characteristic that supply and demand should be equal in each instant. Market parties, such as WPPs, are incentivized to participate actively in the balancing arrangements, by sending accurate schedules to the TSO and participating in the provision of balancing services.

In the Netherlands, WPPs are fully responsible for their imbalances, as any other electricity producer. In addition, imbalance prices are based on the marginal prices of activated downward and upward regulation bids of the balancing energy market. However, the imbalance price also depends on the regulation state as further explained in Appendix D.

The Netherlands applies a mix of single and dual pricing. For 2010, the same imbalance price for both long and short positions was applied in almost 90% of the cases (as a single pricing).

3.3.1 Bidding strategies for a Dutch WPP

This section describes a stochastic optimization model, which aims to minimize imbalance costs. The decision variables of the model are the bids in the day-ahead and intraday markets ($P^D_{h\omega}$ and $P^I_{h\omega}$) that maximize the profits (minimize the imbalance cost) of the WPP. These variables are based on different random parameters (prices and energy forecast) and cross-border capacity between the Netherlands and Germany. With these variables, it is possible to obtain, among other results, the profits of the WPP under different bidding strategies, the economic benefits of intraday trading and final energy imbalances.

There are some underlying assumptions in the model formulation: the WPP does not have market power in the different markets (day-ahead, intraday). The WPP is small and does not affect prices; bids in the markets correspond to the optimal quantities for forecasted prices. The WPP aims to maximize profits/minimize imbalance costs through participation in the day-ahead, intraday markets and determination of real-time energy dispatched. Turbine failures are assumed known before sending bids to the different markets. Wind power and prices are assumed independent stochastic processes. Also, participation in the intraday market is supposed free of charge.

3.3.1.1 Mathematical formulation

The objective function for a WPP that maximizes its profits is described in (3.3.1). The WPP can sell power in the day-ahead market, buy and sell power in the intraday market and finally take decisions on real time power delivered, where deviations from schedules are penalized with short and long imbalance prices. This formulation is similar to the one proposed by Morales et al. [84], but it incorporates the differences in the imbalance penalties and cross-border considerations.

$$\xi\left\{R\right\} = \sum_{\omega=1}^{N_\Omega}\sum_{h=1}^{N_T}\left(\lambda^D_{h\omega}P^D_{h\omega} + \lambda^I_{h\omega}P^I_{h\omega} + \lambda^+_{h\omega}\Delta^+_{h\omega} - \lambda^-_{h\omega}\Delta^-_{h\omega}\right) \tag{3.3.1}$$

The sum of the power bid in the day-ahead and intraday markets is defined as $P^S_{h\omega}$.

$$P_{h\omega}^{S} = P_{h\omega}^{D} + P_{h\omega}^{I}, \forall h, \forall \omega \tag{3.3.2}$$

Then the power deviation incurred by the WPP is described in (3.3.3).

$$\Delta_{h\omega} = \left(P_{h\omega}^{S} - P_{h\omega}\right) = \Delta_{h\omega}^{+} - \Delta_{h\omega}^{-} \tag{3.3.3}$$

Due to dual imbalance pricing used in the Netherlands, it is required to include a binary variable $b_{h\omega}$, which takes the value of 1 if the WPP has negative imbalances and 0 for positive ones.

The bounds of the imbalances are described in (3.3.4) and (3.3.5). The maximum value for the positive imbalance is to send a bid of 0 MW and produce $P_{h\omega}$ (3.3.4) and maximum value for the negative imbalance is to bid in both markets $\left(P_{h\omega}^{S}\right)$ and finally produce 0 MW(3.3.5).

$$0 \leq \Delta_{h\omega}^{+} \leq P_{h\omega}\left(1 - \gamma_{h\omega}\right) \tag{3.3.4}$$

$$0 \leq \Delta_{h\omega}^{-} \leq P_{h\omega}^{S} \gamma_{h\omega} \tag{3.3.5}$$

The power sold in the day-ahead market and the sum of the power bid in the day-ahead and intraday markets should be positive and less than the installed capacity ((3.3.6) - (3.3.7)).

$$0 \leq P_{h\omega}^{S} \leq P^{max} \tag{3.3.6}$$

$$0 \leq P_{h\omega}^{D} \leq P^{max} \tag{3.3.7}$$

The power sold in the intraday market can be negative (which means that the WPP can buy power in the intraday market). From (3.3.6) and (3.3.7), the quantities sold in the markets are bounded by P^{max} and $-P^{max}$. However, when a cross-border intraday market is considered, then the trade possibilities are subject to the availability of Intraday Available Transmission Capacity (IATC).

The IATC has been included for the day-ahead and intraday models formulations. In the present case study, congestions have occurred only in the direction from Germany to the Netherlands. Consequently, for the day-ahead market, a forecast of the IATC has been estimated, and therefore the intraday bids have to be subject to the estimated cross-border transmission capacity. The IATC is included in the day-ahead market formulation by adding a new constraint (3.3.8).

$$P_{h\omega}^{I} \geq -IntCap_{(GE-NL)h\omega} \tag{3.3.8}$$

A non-anticipativity constraint (3.3.9) must be added to the previous formulation, similar as discussed in Conejo [93]. In this formulation, the non-anticipativity constraint is necessary in order to ensure that only one bid can be submitted to the day-ahead and intraday markets, irrespective of wind power scenarios and price scenarios.

$$P_{h\omega}^{D} = P_{h\omega'}^{D}, \forall h, \forall \omega\omega' \tag{3.3.9}$$

The problem can be solved by decomposition of N_h optimization problems, as there are no inter-temporal constraints. The stochastic model has been solved using CPLEX under GAMS.

The model has three stages: in the day-ahead market the WPP submits a bid to the market for the 24 hours of the next day, using power and price forecasts available before the gate closure. In the second stage, once the day-ahead market data (prices and quantities) and IATC are known, the model determines the optimal bid for the intraday market (buy and sell bids). For simplification, the WPP does not affect the intraday prices and bids are cleared at the reference prices of the intraday price. The final step computes the real-time energy dispatch that maximizes the profits based on the bids in the day-ahead, intraday markets, imbalance prices and possible power generated.

The timing of the three stage stochastic model is shown in Figure 3.3.1. It also shows the time when information is available and when the decisions are taken.

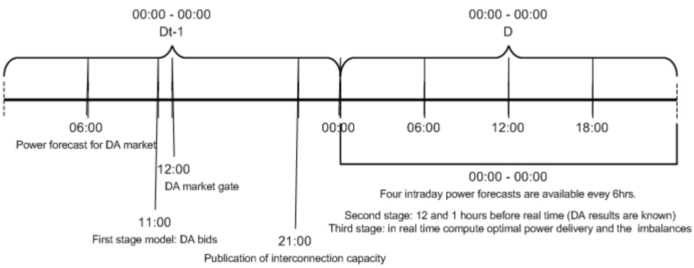


Figure 3.3.1: Timing of the three stage stochastic model

In the first stage, the WPP sends the power bids for the day-ahead market before 12:00 of the previous day ($D-1$), for instance at 11h00. At this time, the wind energy forecast used is the one available at 06h00. There is a long time lag of 18 hours up to 42 hours between the time when the day-ahead energy forecasts are obtained and the operational hour. At 11h00 ($D-1$), intraday prices and imbalance prices of next day (D) are quite uncertain, as the values from 11h00 until the end of the day ($D-1$) are unknown. For simplification, intraday prices of the day before delivery ($D-1$) are assumed as known.

For the intraday market, the already known day-ahead quantities and prices are incorporated. This stage is run one hour before the real time. As IATC is published at 21h00, it will be input data (it is assumed the capacity will remain available, which is not an unrealistic assumption for the data observed in 2010). The energy forecast used for the intraday market has two different time lags: one from 12 to 7 hours before real time (last but one forecast) and time a lag from 6 to 1 hour before the hour in consideration, corresponding to the last energy forecast before real time (see Figure 3.3.1). The intraday bids are cleared at the corresponding market reference price. However, the forecasted bid prices might be out of range of the real intraday prices. As the market is continuous, agents can change bid prices continuously, nevertheless, the intraday market might not be liquid enough to find a counterpart. Therefore, there is a risk that the bids at the forecasted bid prices might not be always accepted. In order to try measuring this risk, after intraday bids are computed, if the forecasted price is out of the corresponding intraday prices range (between the minimum and maximum values) then bids are assumed as non-matched. The profits for the WPP with and without all bids accepted are compared, to have an estimation of this effect.

Finally, in the last stage the WPP decides how much to generate based on expected imbalance prices and the bids sent to the markets. In the Netherlands, TenneT publishes information about the balancing state of the system and the marginal balancing prices each minute. This real-time information of imbalance prices/quantities gives an idea of the price of the PTU (Program Time Unit, which corresponds to a 15-minute period over which imbalances are computed); therefore, imbalance prices are considered known for the last stage. At this stage, it is possible to produce less than the possible maximum output if imbalance prices for long positions are negative and the WPP would have a long position. For simplification, the penalizations in the proposed formulation are computed at hourly basis while in reality they are computed at the PTU basis (15 minutes). As WPPs do not find instruments at 15-minute basis in the day-ahead or intraday markets (15-minute products were introduced in the German market in December 2011), it might induce to higher imbalance costs. Other possibilities, such as bilateral trade every 15 minutes, can help to reduce imbalances in each PTU (however, information about bilateral trade is not available). As imbalance prices are considered known and the rest of parameters are already known, this final step will be reduced to a deterministic optimization.

3.4 Case study

3.4.1 Data description

Wind power data and wind energy forecasts are from Offshore Wind Farm Egmond aan Zee (OWEZ), which is the first big offshore wind farm in the North Sea, near the Dutch coast. The farm is composed of 36 wind turbines of 3 MW capacity each. NoordzeeWind is the company that owns and operates the farm; it is a joint venture between the electricity company Nuon and the oil company Shell. Measured wind power data were provided by NoordzeeWind in 10-minute intervals for 2010. OWEZ receives a feed-in premium of $97€/MWh$. This premium is not included in the model formulation in order to measure the effect of a WPP acting as any other generation unit; nevertheless, it can be easily incorporated as a constant in the objective function.

The wind energy forecast was developed for OWEZ by Dr. Arno Brand from Energy Research Center of the Netherlands. The forecast is based on meteorological weather forecast. It takes into account the farm characteristics such as the turbines specifications, the layout of the wind farm that considers wake effects, the hub-height transformations, and the systematic errors, among other specifications. For detailed description of the forecast methodology, see Brand [94].

The energy forecasts for the considered wind farm have day-ahead and intraday time frame. The forecasts are obtained four times a day: at 00:00h, 06:00h, 12:00h and 18:00h. As the gate closure of the day-ahead market is at 12:00h, the energy forecast used for the day-ahead bids is the one run at 06hr; this means a time lag of 18-42 hours before the operation hours. For the intraday bids, the energy forecast used has two different time lags: one from 7 to 12 hours before real time and the other one from 1 to 6 hours, depending on the hour.

The power data have been converted from 10 minutes measured data into 15 minutes data with a linear interpolation method, the same as used in the energy forecast. Also, the wind power data have negative values (this means that the turbines consume electricity before they start working). Those negative values are transformed into zero values, as the forecast does not consider negative values.

The energy forecasts have been tested in order to see if they have autoregressive patterns. For this purpose, the autocorrelation and partial autocorrelation functions were used. Therefore, a time series analysis is applied, similar to the one used for prices and described in the following subsection 3.5. The correlation coefficient between the day-ahead energy forecast errors of the considered offshore wind farm with the forecast errors of the whole German area (based on the TSOs data) is almost zero (-0.02). This is important to determine if the offshore bids can find a counterpart bid in the intraday market. Another variable that gives signals that the bids could be cleared is the volumes of the intraday market, which in the German case are high (Figure 3.2.2) in comparison with the considered offshore wind farm capacity.

Price data

The prices and power data show both daily and weekly seasonality. These characteristics are considered when modeling the uncertainties.

Day-ahead prices

Hourly day-ahead prices for the year 2010, from the Dutch power exchange (APX), have been used for the modeling. The access to these data was possible due to the cooperation between TenneT and Delft University of Technology. Figure 3.4.1 shows the Dutch day-ahead prices for 2010.

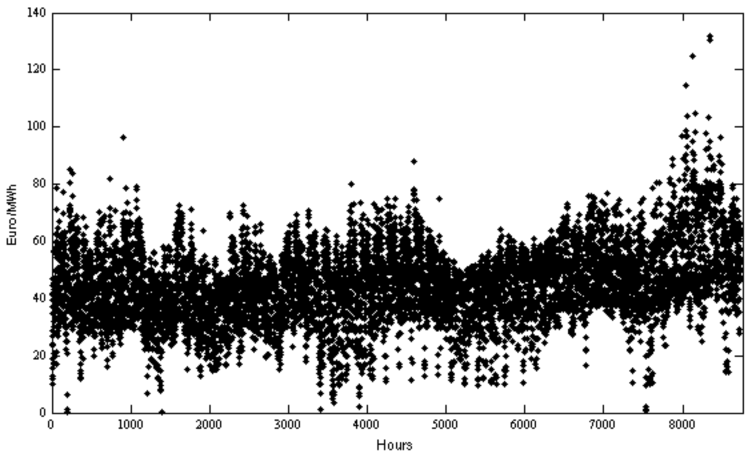


Figure 3.4.1: Dutch day-ahead prices

Intraday prices

As the clearing criterion of the German intraday market considers price and time criteria, there are different intraday prices for the same hour. The maximum, minimum and average (volume-weighted average prices) of the German intraday market price data are available at EPEXSPOT. However, before November 21st 2010 only the maximum and minimum values for each hour are available; from that date to the present date, there is also data of the average price. As the objective is to have just one representative price per hour for 2010, the average price distribution (based on the minimum and maximum values) of the first 6 months of 2011 was assumed to be the same as the one of 2010. Based on the average, the minimum and maximum values of the intraday prices for 2010, the inverse transformation of a triangular distribution was used to generate one single representative value of the intraday price per hour.

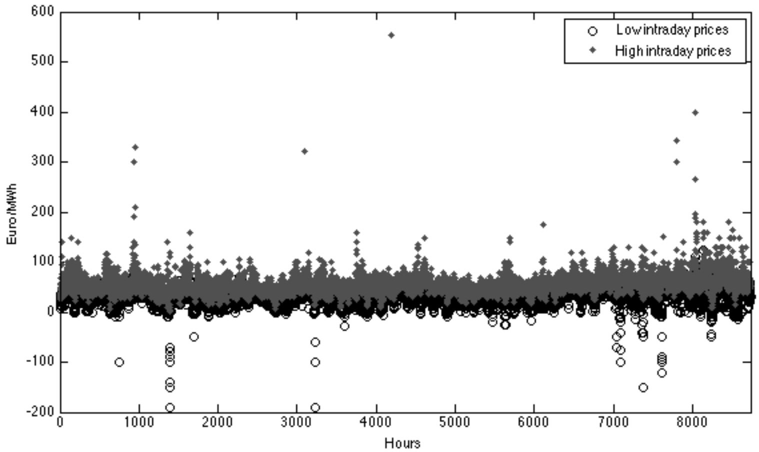


Figure 3.4.2: Low and high values of the German intraday prices

Imbalance prices

Dutch imbalance prices for both long and short positions are available on TenneT website. They are available on a PTU basis, each 15 minutes, the time unit over which imbalances are computed. As the day-ahead and intraday prices are hourly, the time unit of the formulation has also an hourly basis. Figure 3.4.3 shows the Dutch hourly average imbalance prices. A priori, the German intraday market (Figure 3.4.2) seems attractive to avoid such high prices, however, it is dependent on whether imbalances are in the same or opposite direction of the system, as having intentionally imbalances in the opposite direction to the system might be profitable within certain range of imbalance prices.

Figure 3.4.3 shows very negative imbalance prices for short and long positions. The imbalance prices had reached, during 2010, the value of $-200\,€/MWh$.

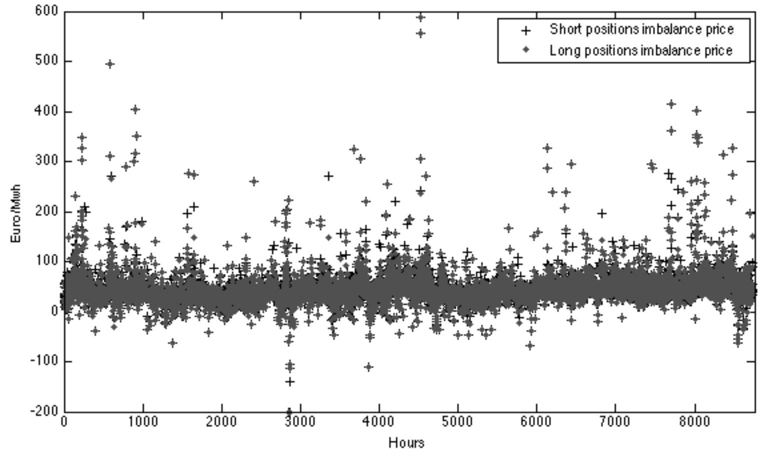


Figure 3.4.3: Dutch imbalance prices for short and long positions

In the Dutch case, the TSO publishes real time (every minute) system balance and the marginal prices of the activated balancing energy. That information gives a good signal of which is going to be the imbalance prices for the whole PTU and it allows WPPs to take decisions about the real time energy dispatch.

3.5 Uncertainty modeling

WPPs who participate in the day-ahead and intraday markets, need to forecast the generation and prices (day-ahead, intraday and imbalance prices) for each hour, in order to compute the optimal bids. Additionally, as in the current case study, available interconnection capacity is an important variable to forecast. To forecast prices, power and interconnection capacity availability, a time series modeling is implemented using a double Seasonal Autoregressive Integrated Moving Average modeling (SARIMA). There is seasonality behavior in the data that comes from daily and weekly patterns of the variables. An outlier treatment of five standard deviations is used. The software used for uncertainty modeling is IDAT, which is a software developed by the Instituto de Investigación Tecnológica from Comillas University. This chapter assumes that wind farm is small and does not affect the imbalance prices[1].

An extended description of time series analysis can be found, for instance, in Peña [96]. The description here is focused on the model identification and its estimation, without entering into details.

[1] Olsson and Soder [95] provide a methodology which considers the effect of wind imbalances on the system balancing requirements and on imbalance prices.

The uncertainty modeling has been carried out as follows:

- Data analysis. The series were studied in order to see if they present autoregressive behavior that can be modeled by a doubled seasonal ARIMA model.
- Stationary testing. The assumption of SARIMA models is that time series are stationary (constant mean and variance). For the stabilization of the mean, a differentiation of the series is performed (integrated component). In order to stabilize the variance, a logarithm transformation (Box-Cox transformation) of the series is applied.
- Scenarios generation. Based on the results of the SARIMA models, 1,000 scenarios have been generated for each variable. Then, the inverse transformation has been applied to get the original scale of the series.

The hourly data, from January to November 2010, are used to estimate the parameters of SARIMA models. The bidding strategies are computed for December 2010 (744 hours). This period is chosen because it includes high negative imbalance prices and congestions in the interconnection capacity. High negative imbalance prices for long positions (downward regulation) might happen in scenarios of high-unexpected wind output and low demand, in combination with thermal generation output near the technical minimums, which makes it costly for them to reduce generation. Table 3.1 shows the best-fitted SARIMA models for the stochastic parameters.

The forecasts are performed at a 24 hours horizon in advance, for the DA market. For the intraday time frame, the forecasts are performed at two different time horizons: at 12 and 2 hours before real time. The power and prices forecasted at the 12 hours horizon do not include the observations after that time frame. For the intraday price forecasting, the German day-ahead price data are included, as explanatory variable, as they are highly correlated. The dynamic regression forecasting modeling (SARIMA model with explanatory variables) was used for this purpose and estimated with the IDAT software.

Table 3.1: Best fitted SARIMA models

Variable	**Model**
λ^{DA}	$ARIMA\,(3,0,1)\,(2,0,1)_{24}\,(1,0,1)_{168}$
λ^{I}	$ARIMA\,(1,0,1)\,(1,0,1)_{24}\,(1,0,1)_{168}$
λ^{+}	$ARIMA\,(4,0,1)\,(1,0,1)_{24}\,(1,0,1)_{168}$
λ^{-}	$ARIMA\,(4,0,1)\,(1,0,1)_{24}\,(1,0,1)_{168}$
$\left(P^{Igen} - P^{Iexp}\right)$	$ARIMA\,(1,0,1)\,(1,0,0)_{24}$
$IntCap_{(GE-NL)h\omega}$	$ARIMA\,(2,0,1)\,(2,0,1)_{24}\,(1,0,1)_{168}$

In order to measure the accuracy of prediction tools for market prices, the Mean Absolute Error (MAE) and the Root Squared Mean Error (RMSE) are computed for the out-of-sample period, which corresponds to the month of December. These measures are defined as follows:

$$MAE = \frac{1}{N}\sum_{i=1}^{N}|e_i|$$

$$RMSE = \sqrt{\frac{\sum_{i=1}^{N}(e_i)^2}{N}}$$

Where e_i is the error in period i, which means the difference between observed and forecasted values.

The values of MAE and RMSE for the market prices, at different horizons, are shown in Table 3.2. The error measures for intraday and imbalance prices are significantly higher than the ones observed for day-ahead prices. Additionally, the errors increase with the time horizon.

Table 3.2: Error measures for the forecasting models

Variable	Horizon (hours)	MAE	RMSE
Day-ahead prices	24	6.66	9.43
Intraday prices	2	11.04	15.48
Intraday prices	12	11.53	15.49
Intraday prices	24	11.77	15.89
Imbalance prices (short positions)	2	13.88	19.48
Imbalance prices (short positions)	12	16.17	22.96
Imbalance prices (short positions)	24	18.16	26.08
Imbalance prices (long positions)	2	13.82	19.38
Imbalance prices (long positions)	12	16. d	22.81
Imbalance prices (long positions)	T	17.94	25.82

From the uncertainty modeling synthetic time series were generated (1,000 per variable). The optimization algorithm is fed with all the different scenarios of the random parameters and provides the best solution that considers all the different uncertainties.

3.6 Results

The results are obtained from different strategies that WPP can use to maximize their profits. The strategies consider three different stages: day-ahead, intraday markets and final energy delivered. Figure 3.6.1 shows the profits of the following different strategies:

1. First strategy. The intraday market is not considered; therefore the optimization model is run for the day-ahead market and it is also possible to adjust generation in

real-time. This strategy is similar to the current case in the Netherlands where the intraday market is not liquid.

2. Second strategy. It consists in bidding the expected energy in the day-ahead market and the updated energy forecast in the intraday market. The deviations from those bids are used to compute imbalance costs. In this case, all the maximum energy possible is delivered.

3. Third strategy. It consists in bidding the expected energy in the day-ahead market and uses the optimization model for the intraday market and real-time adjustments.

4. Fourth strategy. It uses the whole optimization model (optimization at the day-ahead, intraday markets and real-time power adjustments).

For the intraday market, two different timing forecasts have been considered: one from 6 until 1 hour before real time and the other one from 12 until 7 hours before. The last available energy forecast (from 6 until 1 hour before real time), together with the prices forecast computed at 2 hours before real time are used to update last available data before real time. An additional possibility has been computed, which considers the penultimate energy forecast (from 12 until 7 hours before real time), including an uncertainty modeling for the intraday and imbalance prices of 12 hours before real time. With this forecasting time, there are more possibilities to find a counterpart in the market and to change later bid prices if the bids are not cleared.

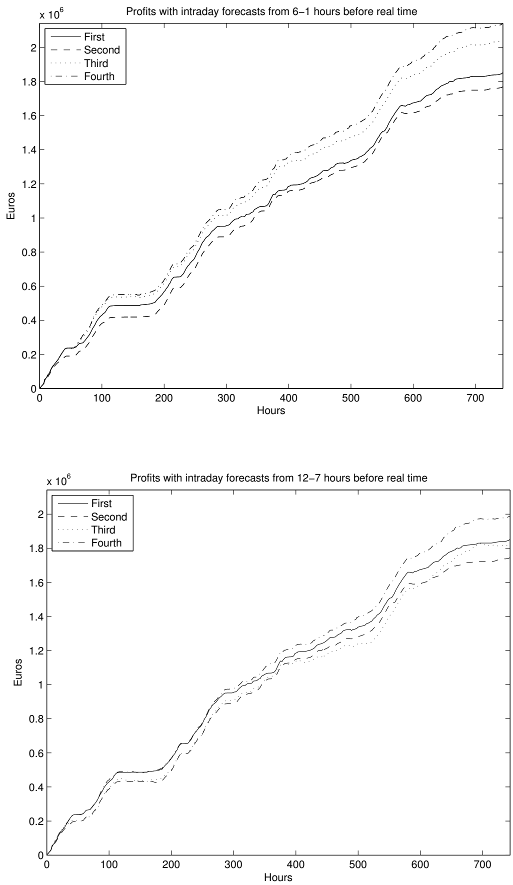


Figure 3.6.1: Cumulative profits for different bidding strategies with different time forecasts

First, the bidding strategies for the intraday market with the last forecasts for energy and prices will be discussed (first graphic in Figure 3.6.1). Then, a brief comparison is presented in relation with the penultimate forecast (second graphic in Figure 3.6.1).

For the last forecasts in the intraday market, the least profitable strategy is the second one (bidding the expected power in both markets), with a total profit of €1.77 million. The most profitable strategy is the fourth one (the whole optimization formulation) with € 2.14 million.

There are different gains of trading in the intraday market: to incorporate new information about energy forecast, take advantage of market data available closer the operational hour and arbitrage opportunities. The overall effect of the intraday market can be determined by comparing the strategies with and without the intraday market. The profit without intraday market is € 1.85 million (first strategy), while the profit with intraday trading is € 2.04 million (third strategy). Therefore, it can be concluded that there are economic gains of trading in the intraday market, of about 4.8% of the total profits. However, the cost of trading in the intraday market is not considered, and it might reduce the gains of this strategy. Those costs, such as fees of the power exchange and personnel costs, can be easily included in the proposed model.

There is a difference between the third and fourth strategies, the results show a difference of around € 0.1 million (4.69%) in favor of the third strategy. This difference indicates the characterization of the stochastic parameters at the day-ahead time frame, such as prices and transmission capacity. In the fourth strategy, with an optimization before the gate closure of the day-ahead market, there are still a lot of uncertainties about market data that will limit the profits obtained. Advanced forecasting tools will increase the profitability of the proposed model. If the model is run with full information about prices and transmission capacity the results obtained are € $2,6$ million. Morales et al. [84] found improvements of 3.273% for units that consider only the day-ahead market based on the forecasting of imbalance prices.

The final imbalances differ from those that would have happened by bidding the expected power in the different markets. The results of the fourth strategy show that, for 15% of the hours, the energy imbalances are within a range of $\pm5\%$ of those that would have resulted from bidding the expected energy. While 57% of the hours ended-up with "intentional" negative imbalances (62% of them were profitable in comparison with bidding the expected energy). Finally, during 28% of the hours, the fourth strategy resulted in intentional positive imbalances, 71% of which were profitable. These results show that the bidding strategies change depending on the different forecasts. Additionally, there are risks associated to them, which lead to losses in some hours in comparison with just bidding the expected energy.

When imbalance prices for long positions are negative and they can be known in advance with high certainty, then it is optimal for a WPP to avoid being long and generate less than the maximum power output (when the feed-in premium is considered, the negative prices have to be higher than the premium to see this effect). If the energy committed in the day-ahead and intraday markets is lower than possible maximum power, then it is better stick to the schedules. If the short imbalance prices are negative too, then it might be profitable for WPPs to generate less than the energy sold in the day-ahead and intraday markets. This strategy was executed in 15 hours of the analyzed period.

Considering a longer time forecast for the intraday forecasts of power and prices (from 12 until 7 hours before real time) the profitability of all the strategies decreases, as expected. However, the order of profitability of all of them remains similar with the last time forecast. The profitability of the fourth strategy decreases on approximately 7% in comparison with using the last forecasts. The profitability of the first and third strategies are similar with almost 1% of difference. Bidding the expected power in both markets and generate all possible power (second strategy), still gives the worst results (around 12% less than the profits obtained with the fourth strategy).

For all the strategies previously discussed, it was assumed that all bids are accepted in the market at the forecasted reference price. However, as the intraday market presents low liquidity, the bids submitted to this market might not all be matched. This issue has been modeled as follows: if the forecasted intraday reference price is without the range of the real market prices, then the bids are not accepted, and the day-ahead bids cannot be modified for those hours. Figure 3.6.2 shows the comparison of accepting all the bids and when not all of them are accepted. In case of forecasts closer to real time, when not all bids are accepted, profits decrease around 3.5%, and using the penultimate forecast the profits decreases in around 5.5% (the data for all bids accepted correspond to the fourth strategy of Figure 3.6.1).

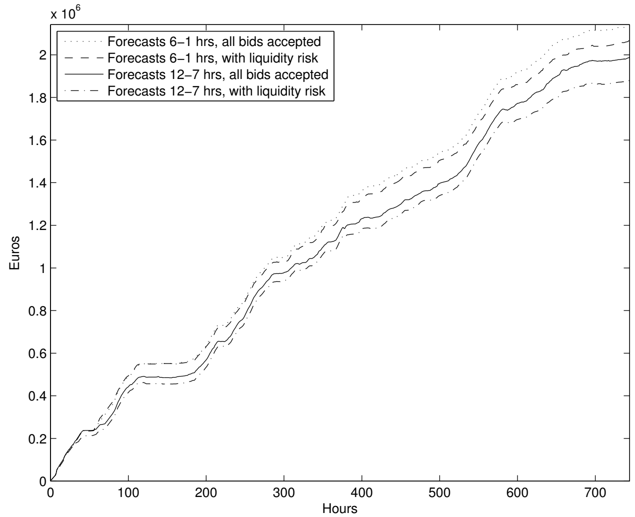


Figure 3.6.2: Cumulative profits by accepting and not all the bids in the intraday market

3.7 Conclusions

The presented methodology shows stochastic bidding strategies formulation for a Dutch wind power producer (WPP) that participates in the Dutch day-ahead market, the German intraday market and adjusts power generated in real time. The results show that the proposed model, considering the German intraday market, gives the possibility to WPPs to update energy forecasts and to realize arbitrage possibilities among the different markets. The model has used different intraday forecasts for prices and power to compare the gains of forecasts closer to real time.

Additionally, it has incorporated liquidity risks measures of not getting all the bids accepted in the intraday market. The expected profits of the proposed model with intraday trading possibilities can increase WPP profits from 7% to 17%, depending on the timing for the forecasting computation and liquidity assumptions. The presented model is novel in the sense that it incorporates cross-border intraday markets and liquidity aspects.

With the imbalance settlement applied in the Netherlands, WPPs are incentivized to create intentional imbalances to maximize their profits and take advantage of favorable imbalance prices. Additionally, it has been shown also that negative imbalance prices for long positions will encourage WPPs to reduce the final generation, if they had a long position. Certainty of imbalance prices is crucial to reduce imbalances costs. In the Dutch case, TenneT publishes information every minute about the system balance and the marginal price of the last activated reserve. Thereby, this information gives valuable signals to forecast imbalance prices and adjust power

Further research might consider removing some simplifying assumptions such as dependency between wind power errors and intraday prices or imbalance prices. Such dependency is especially significant for systems with a high penetration of wind power (in this chapter, it is considered a single offshore wind farm, which is assumed not to have an impact on market prices). Additionally, wind generation units might be part of a generation portfolio, with other generation units, that can be used to have strategic behaviors. In order to consider the influence of market prices, a non-linear approach can be used to compute prices and quantities (the problem then turns into a nonlinear formulation which is computationally more complex, and more information on intraday bids is required, which are not publicly available). Furthermore, it is assumed that trading in the intraday market does not have extra costs in terms of computational efforts nor fees from the power exchange.

Real application of the proposed methodology use different liquidity assumptions at different time frames. The continuous market allows modifying the bids many times when the market is open; however submitting different bids at different time frames will have an additional cost. The presented results cannot assure that the assumed accepted bids in the intraday market would have been accepted, but without data of all bids on this markets it is difficult to be determined.

The current allocation of intraday interconnection capacity between the Netherlands and Germany (first come, first served) is not an efficient way of allocation and pricing of cross-border intraday capacity. The integration of national intraday markets in Europe, with implicit allocation of interconnection capacity, will increase liquidity, give better valuation of intraday interconnection capacity scarcity and decrease imbalance costs associated to the integration of intermittent RES-E. Further strategies, such as include agents that have generation units in both countries (Germany and the Netherlands) that can arbitrate between different markets, can be easily studied with a little extension of the proposed model. The proposed model could also be applied to the aggregation of wind farms that could reduce forecast errors in the different time frames, due to netting of forecast errors.

Chapter 4

Participation of wind power in balancing mechanisms

4.1 Introduction

In Europe, wind power has been participating in different electricity markets. However, direct participation on balancing markets has been restricted in all European countries except in Denmark [97]. ACER [5] requires that Network Codes shall set terms and conditions to allow load and intermittent RES-E to participate in the provision of balancing services. However, the participation of intermittent RES-E in this provision can be done in different ways depending on the designs of the balancing mechanisms.

Intermittent RES-E, such as wind power[1], are technically able to provide balancing services (active power control) [32, 98]. Under certain conditions, the provision of balancing services by wind power can be cheaper than using other power sources, even when considering opportunity costs (which are reflected by the support schemes). For instance, the decrease of wind power can be justified in hours of high wind power generation and low demand, grid congestions and when thermal units face high costs for reducing their output. In addition, wind power should be encouraged to update and disclose wind energy forecasts at different time frames to decrease the needs of balancing services.

This chapter describes those aspects of the procurement schemes of balancing services that might affect the participation of wind power in five European countries: Denmark, Germany, Spain, the Netherlands and Great Britain (GB). Denmark, Ger-

[1]The focus of this chapter is wind power; however, most of the discussions can be applied to solar power but differences between both sources should be further analyzed.

many and Spain already have a high penetration of wind power. The Netherlands and GB are included in the discussion as significant developments of wind power are taking place in these countries. This chapter identifies, under those designs, how wind power can participate in the balancing markets and how those designs need to be adapted to incorporate the characteristics of wind power. This chapter contributes in highlighting some of challenges faced by regulation to allow wind power to participate in the balancing mechanisms. It also provides references to empirical projects and modeling tools to evaluate potential benefits of that participation.

This chapter continues as follows: Section 4.2 describes the procurement designs of balancing services. Section 4.3 focuses on the procurement designs of balancing services for congestion management. Section 4.4 discusses how wind can participate in the balancing markets and possible risks of it. Finally, Section 4.5 concludes and highlights the main findings.

4.2 Procurement designs for frequency reserves

This section provides a critical description of some relevant design variables for the procurement schemes for FRR and RR in the considered five European countries. Table 4.1 gives a general summary of comparable aspects among these countries.

Table 4.1: Market designs for procurement of FRR and RR

(a) Procurement schemes and timing of the markets

Country	Procurement Scheme		GCT Capacity		GCT Energy	
	FRR	RR	FRR	RR	FRR	RR
Denmark (DK1)	Bilateral Contract	Market	Month-ahead	Day-ahead	Month-ahead	45 minutes*
Germany	Markets		Week-ahead	Day-ahead	Week-ahead	Day-ahead
Netherlands	Tenders (Capacity) and Market (Energy)		Year-ahead		1 hour ahead	
Great Britain	Tenders and contracts		Yearly until week-ahead		Yearly until day-ahead	
Spain	Markets		Day-ahead		Day-ahead	35 minutes*

(b) Pricing mechanisms

Country	Capacity Pricing		Energy Pricing		Imbalance Pricing
	FRR	RR	FRR	RR	
Denmark (DK1)	Negotiated Price		Fixed Price	Marginal Price	Dual
Germany	Pay-as-bid		Pay-as-bid		Single
Great Britain	Hybrid		ThereHybrid		Dual
Netherlands	Pay-as-bid		Marginal Price		Mostly Single
Spain	Marginal Price	-	Marginal Price of RR	Marginal Price	Dual

* It is required to bid the day-before, but bids can be adjusted later on.

Tables source: SOs public information and respective legislation updated in July 2013.

4.2.1 Capacity and energy markets for FRR and RR

Capacity markets for reserves ensure their availability. In these markets, TSOs buy contracted reserves based on the expectations of real time needs. The selected bids receive an availability payment. When there is separate market for the energy component, the contracted capacity bidders are usually obliged to bid into this market (at a predefined price, within a certain price range, or they can be free to set the price).

In all the analyzed countries, there is capacity procurement for FRR. For RR, all the countries buy capacity reserves, except Spain, where it is mandatory to present all available capacity for non-intermittent energy sources that are technically able to provide this service. In the Nordic Region and Netherlands, new energy bids that have not participated in the capacity market can bid on an energy reserve market.

4.2.2 Procurement Scheme and Pricing of FRR and RR

The SO can buy balancing services in different ways. Organized markets are usually a preferable option for the procurement of balancing services, as they are transparent and they are open to the participation of different market parties. Bilateral contracts, on the other hand, are less transparent for market parties as prices are usually not published. Tenders are meant long-term auctions, and in the present cases, without publication of the tender results.

In the analyzed countries, the capacity component of FRR and RR is procured differently. In the Netherlands, there are yearly tenders for 300 MW, and bids are symmetrical for upward and downward regulation [99]. The contracted parties that have received a capacity payment should bid in the energy market but with large margins up to $\pm 100000\,€/MWh$. Symmetrical bids are restricted in the way that BSPs can be more suitable to provide just one of the services. In Germany, the TSOs ask for capacity and energy bids on a weekly market for FRR and daily market for RR. During the capacity phase, just the capacity price is considered. The real time activation is based on the energy price [100]. Both prices of FRR and RR (energy and capacity) are set as pay-as-bid.

Denmark is divided in two areas: Western (DK1), which is part of ENTSO-E Regional Group Continental Europe (former UCTE), and Eastern Denmark (DK2) which belongs to ENTSO-E Regional Group Nordic (former NORDEL). For DK2, frequency-controlled reserves and disturbance operation reserves have mainly the function of FCR, and the manual reserves (bought in the Nordic regulating power market) are used as FRR and RR. For DK1, FRR are bought through bilateral contracts. The availability price of FRR is negotiated between Energinet.dk and the bidder. The activation price of FRR is fixed at the DK1 spot price plus 100KK/MWh (~ 13.33 €/MWh) for upward regulation (with a price floor equal to the upward regulating price) and the downward regulation price is settled at the DK1 spot price minus DKK100/MWh (with a price cap equal to the downward regulating price) [101].

In the Nordic Region, there is a single regulating power market for manual reserves, which can have the function of FRR or RR; the market is cleared using marginal pricing.

In Spain, FRR balancing capacity is procured in a specific market, the bids present just capacity prices. The energy price of FRR corresponds to the RR marginal energy price.

In GB, balancing services are bought in different mechanisms that occur at different time frames. These balancing services are shown in Table 4.2.1. The first three rows show the frequency response products (FCR), while the next rows show those that have the function of FRR and RR. Additionally, there are system security services that include, among other services, the transmission constraint agreements, generation curtailment services, maximum generation and exchanges with neighboring SOs. The Balancing Mechanism Units (BMU) are those units that directly participate in the Balancing Mechanism, where National Grid buys balancing services [102].

4.2.3 Timing of the capacity and energy markets

As shown in Table 4.1, the markets for FRR and RR take place from years until minutes before real-time. The Gate Closure Time (GCT) refers to the time after which bids cannot change. Closer to real time, more flexibility is given to market parties to participate in the market and update relevant data in their bids.

In the capacity market, both the capacity and the energy prices can be determined. This is the case for Spain (FRR), Germany and GB (FRR and RR). In Germany, for FRR, the TSOs ask for capacity and energy bids the week-ahead, while the RR capacity market takes place the day-ahead. In GB, most of the contracted reserves are bought with long-term tenders or contracts that happen on a yearly, monthly or weekly basis. Only few reserves are bought at the day-ahead, such as Balance Mechanism Start-up or contracts with neighbor SOs.

In Spain, bids for FRR are accepted until 15:30. The availability of FRR is remunerated with the marginal price. The effective energy delivered is remunerated at the marginal price of RR [46]. In addition, submission of bids for RR is mandatory and takes place at 23:00 of the day before. FRR energy bids are determined the day before, and they cannot change after the GCT, while RR prices bids can change 35 minutes before real time. There are additionally two markets for procurement of balancing services. One called "Gestión de desvíos" (imbalance management), which is organized by the TSO if the expected imbalances are higher than 300 MW. Since May 2012, there is an additional market for upward regulation. The TSO organizes this market when it expects higher upward regulation needs. This market takes

Figure 4.2.1: Procurement designs of balancing services in Great Britain

Service	**Providers**	**Procurement Scheme**	**Payment**	**GCT**
Mandatory Frequency Response	Generation units	Mandatory	Holding and energy response	Monthly
Firm Frequency Response	All units	Tender	Four-part payment structure	Monthly
Frequency Control Demand	NonBMU Demand	Negotiations	Availability	Weekly
Fast Reserve	All units	Tender	Availability, utilization, holding	Monthly
Short-term Operating Reserve	All units	Tender	Availability and utilization	Thrice a year
BM Start up	Generation BMU	Bilateral contracts	Start-up and hot standby	Day-ahead
Transmission Constraint	All units	Markets / contracts	Availability and utilization	As required
Generation Curtailment	Generation units	Bilateral contracts	Utilization	As required
Maximum Generation	Generation BMU	Long-term contracts	Utilization	Long-term
SO to SO Service	RTE, SONI	Contracts	Daily price	Daily

*These data were collected from NationalGrid website on November 20, 2013.

place the day-ahead at 15:00, and bids are accepted within the next 30 minutes.

In the Netherlands, the daily energy market bids for FRR and RR are submitted before 2:45 pm. If the bids are not activated by TenneT, they can change until one hour before execution [103].

In Denmark, RR bids must be submitted before 17:00 of the day before, and bid prices can be adjusted 45 minutes before the delivery hour [97].

ACER [5] argues that the network codes shall allow BSPs to deliver balancing energy without being selected for capacity beforehand. Additionally, ACER [5] proposes the collateralization of reserves, which means that a contacted BSP can purchase reserves from another BSP, as long as the SO is informed and the other BSP is able to provide these reserves. Collateralization of reserves is possible in the Netherlands, Germany and the Nordic Region.

4.2.4 Settlement Time Unit

Settlement Time Unit (STU) refers to the interval when imbalances are computed. Short STU can incentivize intermittent RES-E to update energy forecasts at short time frame. Therefore, shorter energy forecasts can decrease system balancing needs and costs, as market parties submit schedules to the SO for every STU. The STU is 15 minutes in Netherlands and Germany and 30 minutes in GB, while in Denmark and Spain it lasts one hour.

4.2.5 Imbalance pricing

Imbalance pricing refers to allocation of imbalance costs to those market participants that have imbalanced positions with respect to their energy schedules. Usually all market parties are Balance Responsible Parties (BRPs), who must send energy schedules and pay imbalance prices for deviations. Some exceptions on balance responsibility have been applied to wind power (see Chapter 7).

The incentives for BRPs under the two imbalance pricing mechanisms are different. Under single pricing, market parties might participate indirectly in the provision of balancing services, as BRPs receive the resulting price from balancing energy costs. In dual pricing, market parties are incentivized to be attached to energy schedules.

As described in Appendix D, the Netherlands[2] and Germany use single imbalance pricing, while the Nordic Region, Spain and GB use dual pricing.

[2] Although the Netherlands applies dual imbalance pricing, most of the hours it has a single pricing, for further details see Chapter 7.

The imbalance price can be based on the last activated balancing energy bids (marginal pricing) or the average costs of balancing energy. The economic theory argues that marginal pricing gives better incentives to market parties and values better scarcity [102]. In Netherlands, Nordic Region and Spain, imbalance prices are based on the marginal pricing, while in Germany and GB, they depend on the average balancing energy costs. In GB, the main cash-out price (imbalance price in the main system imbalance direction) is calculated as the average of the most expensive 500 MWh balancing actions taken by the SO. GB is moving towards marginal pricing imbalance pricing, as a result of an approved reform on the Electricity Balancing Code [2014]. In Germany, the imbalance prices are the average cost of the balancing energy of FRR and RR.

The correct imbalance price signal also depends on how the balancing capacity prices are allocated to BRPs [21]. ACER [5] supports that the imbalance pricing should be based on marginal pricing, unless the TSOs provide the National Regulators with a detailed analysis which demonstrates that the use of a different price method is more efficient.

4.2.6 Publication time of imbalance prices

Information about system imbalance and prices of the activated balancing energy is important for BRPs to avoid high imbalance costs. If this information is available just after balancing energy bids are activated, it gives an idea of the imbalance prices for the STU, and market parties can react to these prices.

In the Netherlands, the publication of system imbalances and imbalance prices happens every minute, which allows an indirect provision of balancing services. However, balancing capacity payments for FRR are not public. The Nordic countries publish the regulating prices an hour after operation, but these countries are considering to publish regulating prices during the operational hour [105]. In Spain, the SO provides information of FRR prices for each hour of the day, while prices and volumes for activated RR are published at the beginning of each hour. In Germany, imbalances prices are published several weeks after [99]. In GB, imbalance prices are published two hours after real-time. The data published are indicative, as there are ex-post modifications that are computed several hours later.

4.3 Procurement designs of balancing services for congestion management

Congestions occur when a flow in a line exceeds its thermal limits or when the power transported has to be limited due to system security reasons. In the European context, with national and regional prices, internal congestions are solved with a redispatching system (basically from dispatchable generation units). Actions to solve congestions can be seen as a special use of balancing services.

The sooner congestions are known, the cheaper balancing services can be used to solve them. However, with the expected increase of intraday trade due to intermittent RES-E, balancing services for both congestion and balancing purposes can be bought for short-term time frames.

Table 4.2 shows the different schemes for congestion management purposes, in addition to FRR and RR.

Table 4.2: Procurement designs for congestion management services

Country	Procurement Scheme	GCT	Wind provision	Curtailment Payment
Denmark	Balancing market	Day-ahead	Yes	100% Opportunity cost
Germany	Balancing Market / Cost-based	N/A	No	100% Opportunity cost
Great Britain	Tenders and contracts	Yearly to day-ahead	Yes (BM units)	Based on contracts
Netherlands	Balancing market	Day-ahead	No	No compensation
Spain	Balancing and specific market	Day-ahead / Intraday	No	15% Day-ahead price

The four German TSOs, in addition to manual reserves (RR), use a cost-base redispatch to relieve national congestions or congestions within their control zones. The TSOs contractually assure themselves the right to intervene in the generation profiles of individual power plants in case of network congestions [106]. Additionally, the German regulator (BNetzA) gives incentives to the TSOs to reduce the costs of ancillary services (including congestion management). When costs exceed or go below a reference value, the TSO bears or retains 25% of the additional cost. According to BNetzA, the TSOs prefer to apply grid curtailment of renewable sources because the foreseen compensation reduces danger of conflicts [107]. Therefore, the TSOs might have incorrect incentives to overuse wind power curtailment in comparison with re-dispatching other units.

The Netherlands and Denmark use balancing market bids to solve internal congestions. These bids are activated based on the lowest costs limited to grid constraints.

In Spain, after the day-ahead and intraday markets, a transmission constraint mechanism ("Resolución de Restricciones Técnicas") takes place [108]. Only dispatchable generation units can participate in this day-ahead mechanism. In the intraday constraint mechanism demand side can participate.

In GB, there are specific procurement schemes to solve congestions, such as "Transmission Constraint Agreements", where all units can participate through contracts or tenders. Additionally, National Grid (the British SO) can use balancing services to solve congestions. Ex-post, there are computations to separate the costs from both actions and to allocate them. Ofgem [109] reported that from all the actions taken by the TSO from 2009 to 2011, 27% of them were used to solve system constraints.

Wind power can provide balancing services for congestion management purposes. Even considering support schemes, wind power provision of balancing services can be the cheapest option, when thermal units face high costs to decrease their generation due to minimum generation limits or ramp-rates costs. The participation of wind power in the market mechanisms for congestion management allows comparing the costs of different technologies. Any discrimination between wind power and other sources can lead to economic inefficiencies and incorrect incentives.

4.4 Participation of wind power in the provision of balancing services

Wind turbines are technically able to provide ancillary services [98, 32]. Obviously wind power producers (WPPs) can provide balancing services only when wind is blowing. If there is no wind, other units should be able to provide balancing services.

EWEA [40] argues that allowing wind power to participate in balancing markets will offer significant flexibility to the system to use inexpensive balancing sources. Currently few markets allow wind power to participate directly in the balancing markets, such as the Danish [97] and the Australian [110]. In GB, some wind power units can participate in the provision of balancing services, but it is not extended to all units [111].

The Netherlands, Spain and Germany do not allow wind power to participate in the provision of balancing services. In case that downward regulation is needed from wind power, there is curtailment of wind power with different compensation schemes (Table 4.2). More discussion on market designs that affect curtailment of renewable sources can be found in Chapter 6.

Wind energy forecast accuracy improves considerably from the day-ahead until few hours before real-time [26]. Market designs should be adapted to encourage WPPs to reveal more accurate energy forecasts and provide balancing services when the costs are lower than alternative options.

The participation of WPPs in the balancing markets can represent extra profits for them. Also, these markets may increase the system efficiency with the disclosure of information from updated energy forecasts and cheaper balancing services. A detailed discussion on market rules that affect the participation of wind power in the balancing markets is provided in the following sections.

4.4.1 Support schemes

The participation of wind power in the balancing mechanisms will depend, among other issues, on the support schemes and the incentives that they provide. Under feed-in tariff (FiT), WPPs are indifferent to market prices. WPPs are indifferent to sell the power into the day-ahead, intraday or balancing markets (as the income does not depend on market prices). However, if WPPs with FiT are balance responsible, they will care about the accuracy of the energy forecast, as there are some costs associated with imbalances. A limited participation of WPPs with FiT in the balancing market can be possible, and the FiT will represent the opportunity cost.

Under feed-in premium (FiP) or Green Certificates (GC), WPPs are sensitive to market prices. Also, WPPs will decide in which market to sell the power, based on market prices and the energy forecasts at different time frames. The FiP or GC prices will represent also the cost of not generating all possible power.

The allocation of balance responsibility to wind power is a prerequisite for the participation in the balancing mechanisms. Currently in all the countries analyzed, WPPs can be fully balance responsible, as any other market player. Further descriptions of allocation of balance responsibility to wind power can be found in Chapter 7.

4.4.2 Participation of wind power in capacity and energy balancing markets for FRR and RR

This section discusses how wind power can participate in the balancing markets, with a distinction between the capacity and energy markets for balancing services. Wind power is more suitable for balancing energy than balancing capacity. Additionally, the suitability for wind power to deliver upward and downward regulation is different.

4.4.2.1 Wind power participation in the balancing capacity markets

The time of the capacity markets can be an impediment for WPPs to participate in the provision of balancing capacity (availability); day-ahead gate closure time is reasonable for participation of WPPs. However, longer gate closure time (weekly, monthly or yearly) is risky for WPP, and it does not make sense for the system reliability perspective.

For upward regulation, offering reserve capacity and producing less than the possible power does not make sense economically. For WPPs' perspective, the loss of the support scheme for less energy delivered would be higher than an availability payment.

The provision of reserve capacity for downward regulation is more relevant for wind power. WPPs can have some certainty about the generation for the following day and can offer bids for downward regulation. However, the selection of bids from wind power will happen only under extreme cases, when it is costly for thermal units to decrease their output.

4.4.2.2 Wind power participation in the balancing energy markets

The participation of wind power in the balancing energy markets makes more sense as usually energy markets take place near real time. Short-term energy markets allow WPPs to update the updated energy forecasts and reveal this information, and by doing this, it might decrease the activation of balancing energy.

Downward regulation Downward regulation prices are usually lower than market prices mainly because thermal generators could be willing to pay back the energy already sold and save fuel costs. When downward regulation prices are positive, it means that the BSP pays back for reducing their output. In this case, it is not profitable for WPPs to provide downward regulation. However, with negative downward prices, WPPs can be incentivized to deliver downward balancing services, but the prices of these services should be higher than the opportunity cost of delivering all possible generation.

By allowing wind power to participate in the balancing market, it provides the TSO with a market based approach to deal with scenarios such as: high wind power and low demand, high variability or grid congestions. Short-term flexibility and short-term economic efficiency can be gained with this approach. In order to have an efficient market functioning, negative prices should be in place (extended discussion on this issue can be found in Chapter 6).

From an economic point of view, there is an efficient use of wind curtailment, which is determined when the marginal benefit of 1 MWh of wind energy equals the marginal cost of integrating this additional MWh. Therefore, even from a dynamic perspective it is not economically optimum to always avoid wind curtailment at any cost (see Figure 4.4.1). The computation of this optimal level can be a complicated task as there are different storage alternatives available (demand response, electric vehicles, increase of grid capacity). But, non-distorted short-term economic signals (market prices) should be in place to allow the development of efficient solutions.

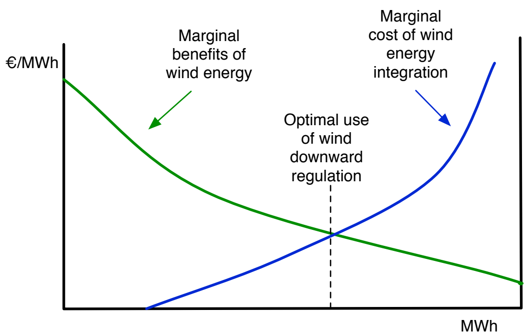


Figure 4.4.1: Theoretical optimal use of downward regulation from wind power

Upward regulation WPPs can provide upward regulation in two ways: first, by not offering all the energy in other markets and offering part of the expected energy for upward regulation. In this case, the incomes for WPPs will depend on the activation of the upward regulation bids and the final energy delivered. There is a risk of not being activated and then increasing the generation by having a long position, but receiving the corresponding imbalance price (with a possible loss in comparison with participating in other markets). Another possibility for WPPs to provide upward regulation is to offer energy in case of energy forecast underestimation. Then, the updated forecast can be incorporated into the market, and less balancing energy would be needed in real time. By allowing wind power to participate in the balancing market there is an economic incentive of improving energy forecasts, which is reflected by the balancing price and the decrease of real-time balancing energy activation.

4.4.3 Active versus passive participation in the provision of balancing services

The imbalance pricing does affect the imbalance costs faced by WPPs (Chapter 7), but also it affects the provision of balancing services. Single imbalance pricing encourages market parties to support the system imbalances, and it is a way of providing balancing services (mainly if the imbalance price corresponds to the marginal balancing price of the energy balancing market).

Table 4.3: Participation of wind in the provision of balancing services

Imbalance pricing	Participate in the balancing market	
	Yes	No
Single	*Active Participation*	*Passive Participation Germany, Netherlands*
Dual	*Active Participation Denmark*	*No Participation Spain, GB**

*Not for all units.

When imbalance prices are negative, WPPs can reduce generation to decrease excess of power in the system. In order to know when imbalance prices will be negative, real-time information about system imbalances and prices of activated reserves is needed, as it is done in the Netherlands. Table 4.3 shows the possibilities of WPPs to deliver balancing services based on the existing imbalance pricing and the direct participation in the balancing markets.

The direct participation of wind power in the balancing markets gives the option (an economic incentive) to WPPs to reveal information before real time. This information is particularly useful as it can change operational decisions that take place close to real time. The indirect participation will produce changes just on real time (however, it still can reduce the balancing costs in real time). However, in case that wind power cannot participate directly in the balancing market, if energy forecasts were underestimated and the system is short, inefficient actions can take place in real time, as the SO can activate upward regulation to solve the system imbalance and then decrease wind power.

4.4.4 Danish experience with participation of wind power in the balancing market

In the Danish market, wind power can participate actively in the Nordic Regulating Market [97]. There are some minor restrictions for wind power in comparison with other sources. For instance, non-offshore wind power farms with a capacity $\geq$ 25MW cannot be pooled with other generation facilities.

In Denmark, a project has been developed to evaluate the participation of wind power in the balancing market [112]. This participation has been tested with an offshore wind farm, Sund & Baelt, which has provided cheaper downward regulation when negative prices occur. Simulations based on historical prices show significant earnings of 5% for a 9-month period. In Denmark, around 500 MW of wind power have been actively providing downward regulation from December 2011 (time when wind power has started to participate in the Regulating Market) to December 2012, and even upward regulation under certain hours of 2012 [113].

In the Spanish market, Saiz-Marin et al. [114] show the economic attractiveness for the direct participation of wind power in the FRR market, which is not currently open to intermittent RES-E. The TWENTIES Project [115] also shows the benefits of provision of balancing services by intermittent RES-E from both wind power producers and the system perspectives.

4.4.5 Possible risks for the provision of balancing services by wind power

Thermal generation sources can determine their generation with high certainty to bid into the different markets (uncertainties are limited and easier to verify by the TSOs). However, this is not the case of wind power. The energy forecasts are almost never certain with a 100% probability, and there is a risk to over/under bid into the balancing markets, intentionally or not. Proper economic incentives should be in place to avoid WPPs having abusive behavior against the system security. Monitoring of energy bids by the SO should be a solution for this; however discrepancies could exist in the use of a “correct” energy forecast, as there are alternative methodologies.

Quantities submitted to the balancing markets

As wind power is intermittent and with limited predictability, it is not clear how to determine and verify bid quantities. The costs associated with an inaccurate provision of balancing services should be allocated to the market parties that do not fulfill their commitment from the balancing bids (therefore, it is necessary to apply cost-reflective imbalance prices).

Prices for the provision of balancing services

Thermal units have some costs/ benefits associated to the provision of balancing services. These costs mainly reflect fuel costs and costs associated with ramping, start-up, shutdown, etc. WPPs have marginal costs close to zero for providing balancing services. However, there is an opportunity cost associated to support schemes that WPPs receive for the energy delivered. Additionally, there are risks associated to the provision of balancing services by WPPs that depend on the accuracy of the energy forecasts (with penalties associated to deviations), and on the probability of being activated.

In some extreme cases, WPPs might be the cheapest ones that can provide downward regulation; therefore, these units might use their position to exercise market power by submitting high prices for decreasing generation. Price caps can be established based in the opportunity costs of each unit. As a general rule, WPPs should not be in a better position without generating in comparison with delivering power. In GB, WPPs that do not want to reduce their output submit high negative prices, but the Grid Code does not specifically account on how to treat these bids that can have prohibitive prices, they can go as far as $-£99999/MWh$ [111]. Already, some experiences of high negative prices have occurred on 5/6th April 2011 and 10-13th September 2011, when National Grid required curtailing wind generation in Scotland due to local constraints [111].

4.5 Conclusions

There are significant differences in the procurement of balancing services (frequency restoration reserves, replacement reserves and balancing services for congestion management) between the analyzed European countries: Denmark, Germany, Netherlands, Spain and Great Britain. Although there are alternative designs for the procurement of balancing services, some general conclusions can be highlighted based on economic efficiency and general guidelines for the design electricity procurement of balancing services, set by ACER [5]: non-discriminatory, fair, objective, market based procurement schemes and with the participation of all units, including demand side and intermittent RES-E. For instance, Great Britain has many schemes for the procurement of balancing services, which can be more transparent if they are merged, and all the units can participate. Additionally, the procurement of balancing energy in a market close to real time can improve the flexibility and efficiency for the activation of balancing services. ACER [5] argues that this market should be open to all market parties that have not participated in the capacity market that can change until one hour before delivery. This is the case of the Nordic Region, Spain and the Netherlands.

With respect to internal congestion management, the Netherlands and Denmark use the same bids from balancing markets. In Germany, apart from balancing bids, there is a cost based redispatch with unequal treatment for wind power that can give inappropriate incentives to the TSOs and the overuse of wind power curtailment. In Spain and Great Britain, there are specific markets to solve congestions. A detailed analysis of the cost and benefits of the procurement of both services for congestion management and balancing should be further analyzed.

Imbalance pricing based on the system marginal cost is a transparent and efficient allocation of imbalance costs. Instead, in Great Britain and Germany the imbalance pricing mechanisms are based on the average costs. In addition, the single imbalance pricing has an effect in the provision of balancing services (indirect participation), which can decrease the system balancing requirements. However, for this passive provision of balancing services, publication of real-time system imbalance and costs of activated reserves is necessary, as it is done in the Netherlands. The single imbalance pricing, in contrast with dual pricing, does not penalize heavier inflexible market players, such as wind power. However, in case of internal congestions, the imbalance pricing should provide correct incentives as discussed in Chapter 5.

The designs of balancing mechanisms can limit the possibilities of wind power to participate, for instance, in the time when the markets take place. However, participation of wind power in the balancing mechanisms permits to compare in a market base approach its opportunity costs with the alternative options. Wind power can provide potential benefits for both the system balancing services and congestion management purposes. Specifically, it can be beneficial the participation of wind power in case of downward regulation when thermal plants face higher costs to decrease their generation. Upward regulation bids might allow wind power to reveal information of updated wind energy forecasts, and it can decrease the balancing requirements. From the countries analyzed, just Denmark allows direct participation of wind power in the balancing market and it has been active in this market. In Great Britain, some wind units can participate, but it is not extended to all.

For the system security's and wind power producer's perspectives, there are some risks of the participation in the balancing market associated with inaccurate forecasts. Therefore, the imbalance prices should be cost reflective to avoid potential gaming in the balancing markets, as bid quantities will depend on the energy forecasts, which cannot be easily verified by the System Operator. Additionally, the payment for the provision of balancing services by wind power should be capped by opportunity cost to avoid possible abusive behaviors.

Chapter 5

The interplay between imbalance pricing and internal congestions

This chapter is based on the work described in Chaves-Ávila et al. [116].

5.1 Introduction

The design of the imbalance pricing mechanisms has been studied before by the literature [21, 117, 118]. However, the interplay between imbalance pricing and network congestions has not yet been studied in detail by the existing literature. Intermittent RES-E increase the occurrence of congestions, especially in the case of wind power which is generally located far from consumption. With internal congestions, imbalance prices may give misleading price signals, depending on the design of the imbalance pricing mechanisms. The conditions for these adverse imbalance price signals are explained in detail in this chapter.

The German market is an interesting case study to analyze the interplay between imbalance pricing and network congestions. Germany applies a single imbalance pricing mechanism for the whole country even in case of internal congestions, while Germany has a significant penetration of intermittent RES-E and internal congestions are increasing. Additionally, Germany is divided in different control zones. Each TSO publishes its own control area imbalances and as well as zonal congestion data. Based on an analysis of the German market, evidence is offered for adverse price signals being given to market participants as a result of the interplay between imbalance pricing design and network congestions. The analysis of the German imbalance pricing can also be extended to other European countries that share similar market designs and an increase of network congestions due to the increase of intermittent RES-E.

This chapter continues as follows: Section 5.2 describes balancing mechanisms in Germany, mainly the imbalance pricing. Section 5.3 focuses on the German internal congestion management. Section 5.4 shows how the imbalance prices can give misleading incentives in the context of internal congestions and provides empirical evidence from the German market. Section 5.5 gives some alternative designs for the imbalance pricing that avoid adverse imbalance price signals in case of network congestion. Finally, Section 5.6 highlights the main findings.

5.2 German balancing mechanisms

Germany is divided into four control zones, each one with a TSO responsible for its zonal balance and security. However, TSOs procure balancing services on a common platform[1] and imbalance prices are the same for the whole country.

5.2.1 Procurement of balancing services

This chapter focuses mainly in the German imbalance pricing mechanism, but this mechanism depends on the energy costs of secondary and minute reserves (FRR and RR, respectively). Therefore, some minor details are given on how these are bought in Germany. Further description of the design of the German balancing service provision can be found in TenneT et al. [99], Hirth and Ziegenhagen [119], Chaves-Avila and Hakvoort [120]. Abbasy et al. [121] argue that the time of the balancing markets take place can have a significant influence in balancing costs. In Germany, FRR bids cannot be changed, neither for capacity nor energy components, after the weekly market, while RR bids cannot change after daily gate closure. Both services are remunerated using the pay-as-bid pricing rule, for both capacity and energy components.

If balancing services are bought after the day-ahead market, the price levels of these bids are similar to what is shown in Figure 5.2.1. When there is a need for upward regulation, those units that were out of the merit order can provide these services at prices higher than the day-ahead market. On the other hand, if there is a need for downward regulation, units that have already sold the energy in the day-ahead market are willing to pay for ramping down, as these units can save their fuel costs (in this case, there are positive prices for downward regulation). Sometimes, the reduction of generation can result in costs higher than savings, due to ramps, shutdown or start-up costs. For the latter, negative prices for downward regulation

[1] www.regelleistung.net, accessed in November 2nd, 2013

can emerge (generation units getting paid for reducing their output). Notice that intermittent RES-E can bid negative prices for downward regulation as they do not have fuel costs, but they have opportunity costs, e.g. the loss of income from not receiving the support scheme.

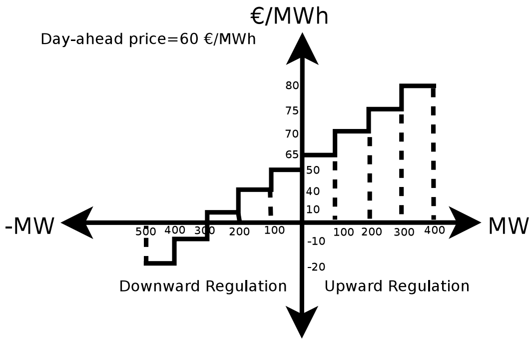
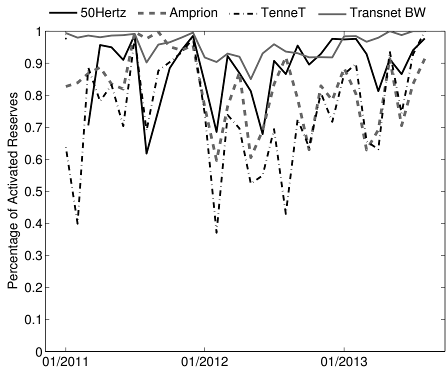
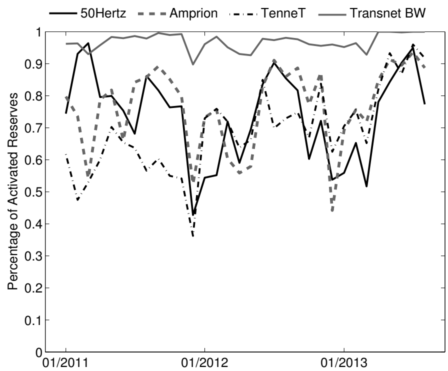


Figure 5.2.1: Illustrative example of merit order of energy balancing services

Just and Weber [23] showed that in Germany during 2009 and 2010, RR were called occasionally. As shown in Figure 5.2.2, from January 2011 until August 2013, all the German SOs predominantly activate FRR in their control areas. As FRR are bought in the weekly market, the relation with the day-ahead market can differ from the one showed in Figure 5.2.1.



(a) Upward Regulation



(b) Downward Regulation

Figure 5.2.2: Activated FRR as a percentage of total activated reserves (FRR + RR). Monthly average values from January 2011 until August 2013

5.2.2 The German imbalance pricing mechanism

Since June 2010, the German TSOs apply single imbalance pricing (reBAP) for the whole country. The imbalance price is based on the average energy costs of FRR and RR. The capacity costs of these reserves are redistributed through the grid tariffs. As shown in Figure 5.2.2, TSOs mainly use FRR, hence imbalance prices mainly depend on the energy component of FRR prices. In December 2012, the Federal Network Agency has introduced modifications in the procedure to compute the imbalance prices as described in Appendix D.

Even with last changes in the German imbalance pricing some concerns remain from the perspectives of efficient cost allocation and efficient price signals:

1. Imbalances prices based on the average cost do not fully reflect the marginal system costs of additional imbalances. This may increase the incentives to market parties to intentionally deviate from energy schedules. Furthermore, adverse price signals can emerge from imbalance prices based on average costs: a market party can create an imbalance (pay the average costs), while a unit owned by this same market party may be requested to provide balancing energy. This is more likely with low competitiveness in the market, which can be the case in the German reserve market [23, 122].

2. As imbalance prices are based on the reserve costs divided by the net activated reserve volume, part of the reserve costs may not be allocated to the hour in which the reserves are activated. This affects the allocation efficiency of balancing costs.

3. The additive or subtractive component to the imbalance prices can affect more those market parties that do not have a generation portfolio to balance themselves.

The literature has pointed out different inefficiencies arising from the German balancing market designs. Just and Weber [23] show the existing arbitrage opportunities for the years 2009 and 2010, as the imbalance prices were on average lower than the day-ahead market. They proposed different alternatives to solve this problem. The first one is to introduce a penalty based on the spot prices. However, as the authors discussed there is a redistribution effect by adding this penalty[2]. Another proposed solution is the introduction of dual pricing, with the disadvantage, as discussed in [21], that this design penalizes inflexible players more, such as intermittent RES-E owners and small players without generation. Just and Weber [23] favor moving the clearing time of the FRR market closer to real-time, to increase the relation between the spot prices and the imbalance prices. Additionally, Just [123] proposed the introduction of a 15 minutes product in the intraday market. Since 14 December 2011, this product exists, but the participation seems relatively low. In April 2013, the trading of the 15 minutes products reached a record, which represented 14.2 % of the trading volume in the German intraday market [124]. The 15-minute product gives better possibilities to market parties to balance their imbalances (especially important for IES).

Haucap et al. [122] showed, by analyzing prices data from 2006 until September 2010, that the synchronization, standardization, cooperation and integration of the German SOs have increased competition in the German RR market. However, Haucap et al. [122] found evidence of strategic behavior in the German FRR capacity market, mainly caused by pay-as-bid remuneration. Haucap et al. [122] used firm data from 2009 and 2010 provided by the German Federal Network Agency (Bundesnetzagentur) to support this finding.

[2] This option is similar to the one implemented by the Federal Network Agency (BK6-12-024) as of 01/12/2012, with the penalty becoming active if more than 80% of the contracted reserves have been activated.

5.3 German congestion management

Germany is divided into four different control zones managed by a different TSO (as shown in Figure 5.3.1): Amprion, TenneT[3], 50Hertz and TransnetBW. In Germany, the penetration of intermittent RES-E is expected to increase congestions. Schmitz and Weber [125] reported a decrease in redispatch actions between 2007 and 2010, but these actions have significantly increased from 2010 to 2011. The moratorium on nuclear power has caused an increase in redispatch in 2011 [125]. In addition, a significant amount of wind power is located in the North of the country (in the control zones of TenneT and 50Hertz), whereas important consumption areas are located in the South.

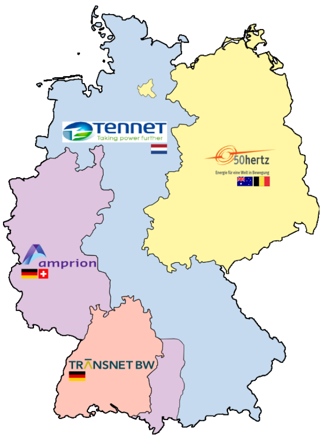


Figure 5.3.1: German System Operators control area

The four German TSOs, in addition to RR, use a cost-based re-dispatch to relieve internal congestions[4]. The TSOs contractually assure themselves the right to intervene in the generation profiles of the power plants in case of network congestions [106]. Additionally, the German regulator (BNetzA) gives incentives to TSOs to reduce the costs of ancillary services (including congestion management).

5.3.1 Evidence of internal congestions in Germany

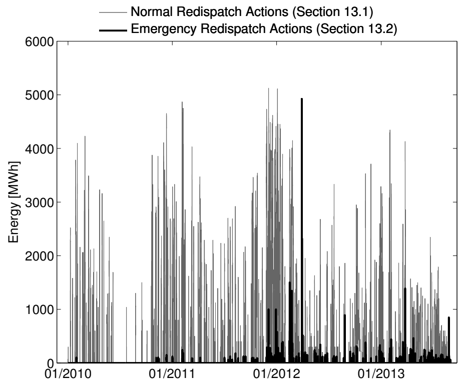
Two of the German TSOs (50Hertz and TenneT) publish congestion management outages) which is ruled in Sections 13.1 and 13.2 of the German Energy Industry Act. Section 13.1 allows SOs to use preventative or curative measures, which include

[3]Notice that TenneT is also the Dutch TSO, however in this chapter it refers only to the German control zone.

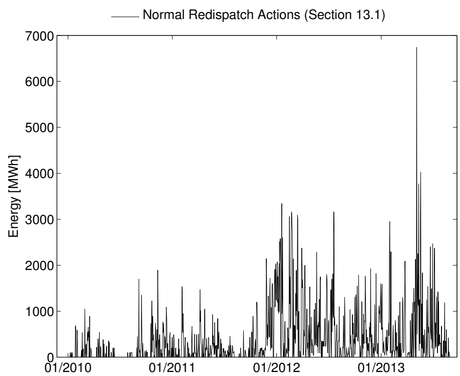
[4]Further research should study in detail the interrelation between the procurement of balancing services and network congestions.

redispatch and counter-trading, as well as safety-related interventions within control areas to modulate power feed-ins. Section 13.2 refers to the use of actions when there is a risk of a disruption that cannot be remedied, or not remedied in time. In such cases, TSOs are entitled and obliged to modify all power feed-ins, electricity transits and take-offs in order to meet the requirements of safe, secure and reliable operation, or to demand such modification.

Figure 5.3.2 shows the actions in the frame of congestion management in the 50Hertz and TenneT areas from January 1st, 2010 to August, 2013. 50Hertz publishes data for every 15 minutes interval. 50Hertz used actions which correspond to the Section 13.1 during 23% of the time in the analyzed period, compared to 5% actions from Section 13.2. TenneT publishes daily data about actions that correspond to Section 13.1. In total, these interventions occurred in 63.3% of the days. The data reveal only two days in which TenneT has used actions that correspond to Section 13.2. In both areas, redispatch actions appear to be frequent.



(a) 15 minutes redispatch actions used by 50Hertz



(b) Daily redispatch actions used by TenneT

Figure 5.3.2: Actions used for redispatch management in 50Hertz and TenneT zones, from January 1st, 2010 until August, 2013.

Since March 2012, 50Hertz has published the load flow data of its transmission system. 50Hertz continually updates power flow data of 185 power lines. Additionally, in each hour, 50Hertz differentiates the degree of capacity usage of the lines by colors. The red color indicates capacity usage greater than 70%, and the line is at the capacity limit in case of failure. Table 5.1 shows the five most congested lines (those that have been marked red in most of the hours). From March 2012 until August 2013, the most congested lines are within Germany, and they are more congested than any interconnection between the 50Hertz area and neighbor countries, such as Denmark, Poland or the Czech Republic. This shows the severity of congestions within Germany.

Table 5.1: Five most congested lines in the 50Hertz control zone

Line number	From	To	Number of hours congested
414	Remptendorf	Redwitz	798
413	Remptendorf	Redwitz	458
306	Pasewalk	Vierraden	756
551	Schmölln	Bärwalde	1721
552	Schmölln	Bärwalde	398

5.4 Imbalance settlement with internal congestions

A single procurement of reserves such as the one implemented in Germany for the whole country and the close co-operation between TSOs contribute to the use cheapest reserves to restore the system balance [122]. However, if there are congestions between two different zones, the energy transfer between zones is limited. Therefore, the activation of reserves in Germany might not follow a common merit order, as it is subject to transmission capacity availability.

The single pricing mechanism, such as implemented in Germany, allows that market parties, having an imbalance in the opposite direction of the net system imbalance, profiting from this, but it worsens the local imbalance at the same time. Figure 5.4.1 shows this situation with a very simplified example of a market with two control zones. This market has a common day-ahead price and a single imbalance price (based on average price of activated balancing energy bids). The energy costs correspond to the merit order shown in Figure 5.2.1, where upward regulation bids belong to Zone 2 and downward regulation bids to zone 1. There is a single interconnection between both zones, which is congested in real-time. Reserve capacity costs are not considered in this example, neither the differentiation between FRR and RR.

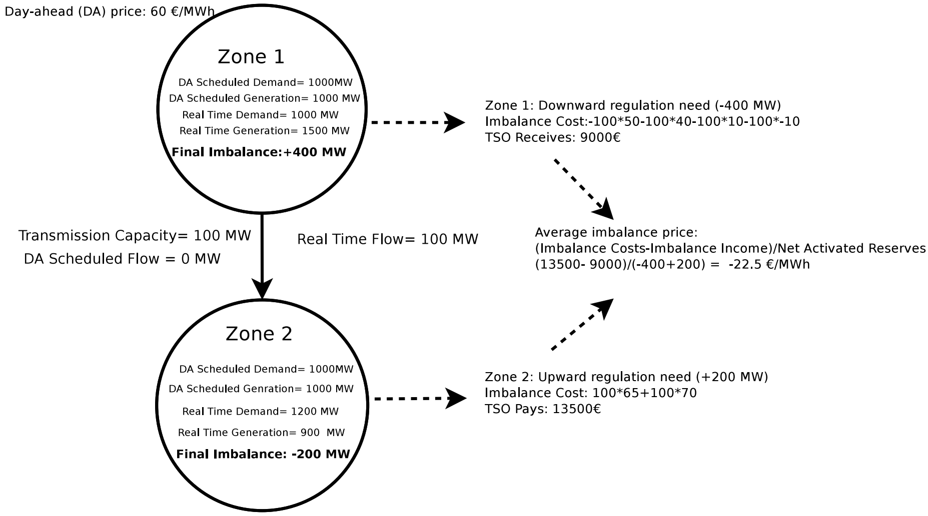


Figure 5.4.1: Illustrative example of single imbalance pricing with congested areas

Based on the data presented in Figure 5.4.1, the resulting imbalance price for both areas is -22.5 €/MWh. However, according to the changes introduced in the German imbalance pricing mechanism in December 2012, the imbalance price would be limited to -10 €/MWh. BRPs pay 10 €/MWh for long positions and receive 10 €/MWh for short positions, independently of the zones they are located. At this imbalance price, BRPs from both zones are incentivized to be short (generate less than sold or consume more than bought), as they can gain 70 €/MWh, which corresponds to the difference between the day-ahead price and the imbalance price (until the net imbalance is reverse). However, this passive balancing would worsen the energy balance in Zone 2. This is an extreme illustrative example because of relative imbalance prices and market parties willing to produce at those prices, but this is not unrealistic example as negative imbalance prices often occur in Germany. This simplified example gives an idea of misleading incentives of a single imbalance price for the whole country based on the average energy costs of reserves and with internal congestions.

5.4.1 Conditions for misleading imbalance prices under internal congestions

To sum up, the following conditions need to be present at the same time for having misleading imbalance prices in the context of internal congestions:

1. Single imbalance pricing scheme for the whole country.
2. Different imbalance direction (electricity surplus and shortage) in different

areas.

3. Congestions between areas.

4. Additionally, in the German case, some regulations on the reserve procurement and imbalance settlement can worsen the imbalance prices signals: new energy bids cannot be submitted after the clearance of the weekly FRR tender, there is no differentiation of reserves prices by hours (only peak and non-peak products), and the reserve energy bids are priced using the pay-as-bid pricing.

In order to profit from misleading price signals, market parties need to have an accurate forecast of zonal imbalances, imbalance prices and grid congestions. For this forecast, information close to real-time is required. In Germany, the final imbalance prices are published a month after delivery due to ex post computations. However, TSOs currently publish, within minutes, information about the control area balance and activated reserves in their control zones in the common platform for reserve procurement. In addition, TSOs publish in that platform the anonymous bids (which include quantities, and prices for capacity and energy components) of the weekly tender of FRR reserves and the daily tender of RR. All these data of control area imbalances, activated reserves and reserve bids give signals to market parties of what would be the amount of activated reserves and the cost of them. 50Hertz also publishes the hourly real-time electricity flow in its control area and shows the congested lines. Therefore, market parties have significant information to react to the control area imbalances, and in the 50Hertz area they can know which lines are congested in real time.

Furthermore, those market parties that have participated in the reserve tenders and whose bids have been activated by TSOs, have more information about the location and costs of the activated reserves. Hence, they have more information to react to imbalance prices. If imbalance prices give misleading incentives that affect local imbalances, those market parties have more information to profit from misleading signals.

The discussed problems of the single imbalance pricing mechanism under network congestions can be solved by increasing transmission capacity between congested areas. However, network expansion takes even longer time than generation expansion [126], and in some cases it is not economically optimal to expand the network. Therefore, a proper imbalance pricing mechanism should be in place and compatible with cases of network congestions, as further explained in Section 5.5.

5.4.2 Evidence of adverse price signals in the German market due to the imbalance pricing mechanism

When the German TSOs deviate from the merit order to activate balancing energy bids, they publish the time when it happens and for how long that occurs (prices and quantities of those actions are not published). These data can be found in the control reserve platform. A deviation from the merit order list (MOL deviations) occurs under circumstances like temporary congestions, unavailability of bids, etc. Additionally, congestions can make it necessary to, on beforehand, plan or constrain the energy exchange between the control zones. Table 5.2 shows the total time (measured in minutes) during which the MOL deviations occurred during 2011 and 2012 in the German TSOs' zones. In Table 5.2 no distinction is made between negative and positive reserves. These figures show only the cases in which grid congestions caused local activation of reserves that deviates from the common merit order.

Table 5.2: Duration (in minutes) of activated reserves of merit order list deviations (MOL deviations) due to network reasons

Description of MOL deviation	**50Hertz**		**Amprion**		**TenneT**		**TransnetBW**		**Total**	
	2011	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**	**2012**
Operational network congestion RR	-420	1542	0	0	0	0	0	0	5420	1542
Congestion request RR	0	4777	0	840	0	1334	0	285	0	7836
Local MOL deviations RR	0	15	0	30	0	30	0	15	0	90
Restriction of the energy exchange FRR	10717	13869	2596	3377	0	0	6635	3437	19948	20683
Local MOL deviations FRR	480	5692	8378	Ho	2405	3292	16	62	This	9891
Total MOL deviations (FRR+RR)	16617	25895	10974	are	2405	4656	6651	3799	36647	39442

Most of the MOL deviations were activated in the 50Hertz area and corresponded to FRR. From February 2013 onwards, the data of MOL deviations from RR are not published separately for each TSO anymore. In the first four months of 2013, during 1665 minutes RR out of merit order were activated due to congestion purposes for the whole country. In the 50Hertz zone, during 4166 minutes, FRR were activated out of merit order. These data show that the activation of MOL deviations has been frequent in Germany. If the share of intermittent RES-E increases, congestions can become more frequent.

For the German case, some concrete examples of adverse price signals can be highlighted, limited by the publicly available data. Table 5.3 shows the prices and energy imbalances for some hours when adverse price signals could have occurred as result of internal congestions and single imbalance pricing.

Table 5.3: Examples adverse price signals in the German market

Date	Net System	Control Zone imbalance (MW)				Prices (€/MWh)		
	Imbalance	50Hertz	Tennet	Amprion	TransnetBW	Imbalance	Intra-day*	Day-ahead
22/09/2012 17:30-17:45	11	-502	167.2	-152	497.7	190.96	44.79	34.Pl
22/09/2012 17:45-18:00	579	-269	422.8	-158	582.9	163.34	45.02	34.31
22/09/2012 18:00-18:15	-628.9	-783	509.9	-60	-295.8	-6.87	17.84	42.44
22/09/2012 18:15-18:30	-422.9	-456	440.1	-188	-219.1	-23.84	25.2	42.44
30/01/2013 09:30-09:45	455.1	-812	2003.8	-134.7	-602	238.5	30.8	37.52
30/01/2013 09:45-10:00	471.6	-801	2091.1	-125.5	-693	215.7	29.4	37.52

*Volume-weighted average intraday prices for the corresponding 15 minutes products.

50Hertz publishes that on September 22th 2012; from 17:00 to 18:00, the line 414, which lies between 50Hertz to TenneT, was congested. Additionally, 50Hertz reported the activation of FRR MOL deviations from 10:30 until 19:31. From 17:30 to 18:00, the German system as a whole was short (a positive sign means need for upward regulation). The corresponding imbalance prices were very high in comparison with the day-ahead and intraday prices. However, the 50Hertz area was long. At those imbalance prices, in the 50Hertz area there were incentives for market parties to be long (increase generation or decrease demand), and they could have worsened the imbalance of this control zone. In the next two quarter hours, the overall German system imbalance was long and imbalance prices were significantly lower than spot prices. However, TenneT control area was short, and market parties could have increased imbalances in this control area (by having short positions) and could have profited from it.

After the changes in the imbalance pricing mechanism in December 2012, possibilities for adverse price signals existed as these changes do not deal with the effect of network congestions. For instance, during January 30, 2013 from 7:15 until 14:02, 50Hertz reported the activation of FRR MOL deviations. Additionally, in the hour 09:00-10:00, lines 413 and 414 (between 50Hertz and TenneT) were congested. As shown in Table 5.3, although Germany as a whole had a need for upward regulation, the 50Hertz control area needed downward regulation. The corresponding imbalance prices were significantly high, which could have incentivized market parties from 50Hertz to have long positions in real time. Again, this could have increased the imbalance in 50Hertz control zone.

The examples from Table 5.3 show some cases when the imbalances directions differ between the German SOs control zones. However, these arbitrage opportunities can emerge even within a single control area, affecting the local imbalance. More detailed information about local area imbalances is necessary to show that when MOL deviations have been activated due to congestions, misleading incentives can emerge and increase local imbalances.

5.5 Alternative designs for imbalance pricing mechanism

This section discusses alternative designs for imbalance pricing mechanism in the context of internal congestions to avoid adverse price signals that can worsen the energy balance, the efficiency of the balancing mechanisms and total balancing costs.

The recommendations made by the literature on the procurement designs of reserves in the German case study (see Just and Weber [23], Hirth and Ziegenhagen [119], Chaves-Avila and Hakvoort [120]) are not further considered in this section. Short-term procurement of reserves and marginal pricing can improve the functioning of the balancing market. The alternative imbalance pricing mechanisms presented in this section aim to avoid adverse price signals for market parties that can affect the local energy imbalance. All the proposed alternatives assume an imbalance pricing mechanism based on the marginal price of activated balancing energy and day-ahead procurement of balancing energy, with possibilities to adapt energy prices close to real-time.

5.5.1 Nodal single pricing

The imbalance prices computed at the nodal level differentiate balancing costs from one node to the other. This gives a cost-reflective allocation of balancing services and avoids misleading incentives to market parties. The corresponding imbalance prices are based on nodal imbalances, therefore there is no possibility to intentionally create an imbalance in the same direction of the nodal imbalances and gain out of it. However, for a nodal imbalance pricing implementation, it is necessary to have nodal prices in the day-ahead and intraday markets. The implementation of nodal pricing depend on a broader design of the German electricity market and even in the European market design, which increases technical complexity and it can be political sensitive [127].

5.5.2 Zonal single pricing

An intermediate solution in dealing with internal congestions with single pricing, is to identify zones based on frequently congested transmission lines. Zonal pricing is being applied in Europe in the Nordic Region and Italy. In Germany, such congestions zones delimitation would not necessarily correspond to the German TSO control zones, as congestions can occur within the TSO zones. It remains difficult to define zones in a manner that avoids congestion within a zone, especially in meshed grids [34]. Instead, the literature on congestion management usually recommends the direct implementation of nodal pricing [128, 34, 129, 126].

The E-Price Project[5] recommends the use of nodal or zonal pricing for ancillary services. Jokić [130] argue that spatial consideration increases reliability at the lowest costs. This is because electricity as a commodity has a locational cost, and the cost of delivering balancing services strongly depends on the network state and characteristics. The zonal imbalance pricing requires as well zonal pricing in the day-ahead and intraday markets and it is easier to implement in comparison with nodal pricing. However, the literature recommends nodal pricing from the economic efficiency perspective and to avoid any further gaming possibilities.

5.5.3 Dual pricing

Dual pricing prevents incentives to deviate from the day-ahead or intraday schedules[6], as deviations are usually penalized, in the most favorable case, with the corresponding day-ahead prices. In the illustrative example of Figure 5.4.1, by applying dual pricing market parties that have short positions (helping to restore the whole system balance), pay the day-ahead price of 60 €$/MWh$, whereas the market parties that have long positions pay 10 €$/MWh$. At these prices, there are neither incentives to help to restore the system balance in real-time, nor incentives to worsen the zonal system imbalance and gain out of it.

However, researchers have discussed different disadvantages of dual pricing [21, 131, 10]: negative impact on small users and intermittent RES-E, and elimination of the incentives for real-time contribution to system balancing, lower the efficiency cost allocation, among others.

5.5.4 Mix of single and dual pricing based on regulation states

In the Netherlands, imbalance prices are based on the marginal prices for downward and upward regulation balancing energy bids. However, the imbalance price also

[5] www.e-price-project.eu

[6] Intraday prices are not usually considered in dual pricing, but they should be further considered as this market becomes more relevant.

depends on the regulation state (see Appendix D).

The Dutch imbalance pricing mechanism does not take into account network considerations. With this design, in case of congestions and opposite imbalances direction in different zones, the marginal price for upward and downward activated reserves are used to separately set the imbalance prices for the whole country for short and long positions, respectively. In the illustrative example shown in Figure 5.4.1, by applying the Dutch marginal pricing rule, the imbalance price would be -10 €$/MWh$ for long positions and 70 €$/MWh$ for short positions. The problem with this design is that if there were short positions in zone 1, they would have been penalized by 70 €$/MWh$, even if market parties with short positions were helping to solve the local imbalance. This creates a larger net settlement sum for SOs in those STUs, which results in a lower efficiency of cost allocation.

An alternative imbalance pricing mechanism can be applied in Germany (or in any other European country with internal congestions) using regulation states, similar to the Dutch imbalance pricing mechanism. But when there are not significant congestions, single imbalance pricing can be applied based on the net system imbalance (Dutch regulation states 1 and -1). In case of internal congestions and imbalances in opposite direction between the zones (energy shortage and surplus), there is no longer a benefit in single pricing for supporting the system balance in real time is not longer valid, as there is no an unique imbalance direction. In this case, a dual pricing mechanism can be applied to prevent misleading incentives to worsen local energy imbalances. The imbalance pricing mechanism should also consider the intraday prices to avoid any further distortion. For the market parties that have sold energy in the intraday market, the relation between the intraday and imbalance prices represent the opportunity cost to deviate. Furthermore, in order to ensure short-term flexibility and efficiency gains of reserve energy bids when dual pricing is applied, it is important that reserve bids can be updated at least to one hour before real-time, as it is done in the Netherlands or the Nordic Regulating Power Market. This imbalance pricing scheme does not require a substantial change in the current market regulations, but it does not provide a robust solution to the problem as nodal pricing.

5.6 Conclusions

The increasing penetration of intermittent RES-E requires a proper functioning of the balancing mechanism, as these sources cause network congestions and higher energy imbalances. Since imbalance pricing gives incentives to market parties to submit accurate energy schedules and support the system balance in real-time, the imbalance pricing mechanism should be designed to give correct incentives to market parties.

In the last years, the German balancing design has been evolving, but still there are concerns about design elements in terms of short-term efficiency: the time at which reserve bids becomes final is long before the time of dispatch (week ahead for FRR and day ahead for RR), the pay-as-bid pricing structure of reserves (both capacity and energy components) and imbalance prices based on the average energy costs of these reserves, among others. In addition, the German imbalance pricing mechanism can give adverse price signals under network congestions.

This chapter illustrates the adverse incentives potentially occur with an imbalance pricing mechanism based on the average reserve costs for a country with internal congestions. Moreover, congestions frequently occur within the German electricity system, which under certain circumstances, provide incentives for market parties to deviate from the energy schedules in the opposite direction of the system imbalance (increasing the local energy imbalance). To mitigate congestion between German control areas, the system operators activate reserves out of the common merit order. Market parties may assess, based on the data published by the system operators close to real time, when imbalance prices can be profitable and eventually they can deviate from the energy schedules. Furthermore, market parties that have participated in the reserve market have more information to react to imbalance prices, which leads to unequal market conditions.

This chapter provides alternative designs for the imbalance pricing mechanisms avoid gaming opportunities in case of network congestions. The nodal pricing with single imbalance mechanism provides locational price signals of balancing costs and avoids the discussed adverse price signals. However, nodal pricing with single imbalance mechanism also requires nodal day-ahead and intraday prices, otherwise additional inefficiencies may emerge. Furthermore, the implementation of nodal prices implies a significant change in the market design, which increases technical complexity and it can be political sensitive currently in Europe.

Without applying nodal pricing, a second best option based on the mix of single and dual imbalance pricing mechanisms with on regulation states, may avoid adverse price signals in the current German imbalance pricing mechanism. For hours without congestions (or very few congestions), a single imbalance pricing mechanism can be applied, preferably based on the energy marginal costs (requiring the balancing energy pricing mechanism to be changed from pay-as-bid to marginal pricing). In case of congestions, and activation of both upward and downward regulation, dual pricing prevents adverse incentives that may worsen the local energy imbalance. This design may be suitable for other European countries that have similar market designs (national prices for spot markets and energy imbalances) and will face an increase in internal network congestions due the to increase of intermittent RES-E in their systems.

Chapter 6

Alternatives for the European priority dispatch rule for RES-E

This section was done in cooperation with Fernando Bańez-Chicharro and Kristin Dietrich from Comillas University, who helped in the modeling section to adapt the ROM model to the objective of this chapter. The author also would like to thank the comments from Prof. Andrés Ramos from Comillas University.

6.1 Introduction

This chapter studies the market designs relevant for situations with high intermittent RES-E penetration. The electricity system might reach tight conditions especially with high penetration of wind power. This is becoming already a concern of some European countries. Regarding these conditions, the priority dispatch might lead to inefficient economic dispatch and also to situations where it is necessary to decrease the intermittent RES-E feed-in (intermittent generation curtailment). These tight system conditions can be grid congestions, or situations with low demand (during night hours, for instance) and high wind. Additionally, in order to maintain the security of the system, it could be necessary to reduce generation quickly. For example, wind turbines might provide quicker ramp rates than thermal units in a security event. Whenever it is necessary to reduce generation from intermittent RES-E, the question then arises if intermittent RES-E producers should receive a compensation for the power curtailed or not. In case that compensation is established, then the challenge is how it should be designed to give the correct incentives to market parties. In Europe, there are different designs to compensate intermittent RES-E curtailment. On one hand, curtailment compensation has an impact on the revenues of intermittent RES-E producers; on the other hand, different curtailment compensation schemes give different values to generation from intermittent RES-E units under tight system circumstances and, therefore, different costs of using intermittent RES-E curtailment. Additionally, there are costs faced by other market players such as consumers and producers with conventional units.

This chapter focuses in the Spanish case based on expected intermittent RES-E targets for 2020. Although the Spanish market has been successful to integrate renewable sources, further developments might foster this integration and improve economic efficiency. Different market rules affect the curtailment of intermittent RES-E in the Spanish market. Alternative designs are proposed to use intermittent RES-E curtailment in an economic efficient manner, and at the same time, align the Spanish market with the rest of the European markets. These changes can reconcile short-term prices with long-term signals necessary to adapt to a system with high penetration of intermittent RES-E. The contribution of this chapter is to measure the distributional effects in terms of operational costs of removing the priority dispatch rule for renewable sources and including negative prices in the Spanish market. To the authors' best knowledge, this type of analysis has not been published earlier.

This chapter continues as follows: Section 6.2 describes the priority dispatch rule for intermittent RES-E. Then, Section 6.3 discusses the support schemes for renewable sources that are currently in place in Spain and Europe. Section 6.4 discusses the importance of negative prices to integrate intermittent RES-E in the market. Section 6.5 describes the mechanisms for intermittent RES-E curtailment in different European countries. Section 6.6 presents an evaluation of market changes with respect to the intermittent RES-E curtailment for the Spanish case study for the 2020 scenario. Section 6.7 presents the model results. Finally, Section 6.8 concludes and gives some policy recommendations.

6.2 Priority dispatch for renewable sources

The so-called "priority of dispatch" rule included in the EU legislation (under Directive 2009/28/EC) implies that renewables sources can only be limited because of security reasons, even if a unit commitment algorithm indicates that it is cheaper to curtail wind or other renewable sources [25]. The rationale followed by this rule is to meet the renewable targets and to incentivize flexibility of the system. The downside of this rule is that it may cause economic inefficiencies in the short-term markets. The alternative of putting renewables sources[1] in the market increases investment risk and the long-term commitment of renewables sources. The effect of this priority rule should be studied in more detail comparing both, short-term with long-term efficiency to fulfill the renewable targets. However, the European Commission [35] has given more relevance to short-term efficiency gains and argues that as markets evolve and grid operations become more neutral, the priority dispatch rule becomes

[1]Notice that the main analysis of this paper is on intermittent RES-E (wind and solar), but some regulations affect all renewable sources such as the priority dispatch, indistinguishable of their nature.

unnecessary. The elimination of this rule for existing units can be conflictive as this right has been already granted. Additionally, in case that it is not longer available for new installations, these last ones will face higher risks of curtailment. Therefore, for new installations, possible curtailment compensation mechanisms will play an important role.

The priority dispatch rule has been interpreted differently between European countries and it strongly depends on the market designs, such as the existence of negative prices and the curtailment compensation. According to Eclareon [132], in the EU 27, 10 Member States do not have legally established purchase obligation for renewable sources: Belgium, Denmark, Estonia, Finland, Great Britain, Ireland, Latvia, Netherlands, Romania, Sweden.

In Spain, priority dispatch has been granted to renewable sources, being intermittent RES-E (without including those that belong to ordinary regime, such as large hydro), the last to be curtailed in case of technical restrictions REE [46]. Curtailment of any energy source is compensated by 15% of the day-ahead market [133]. In Spain, negative prices are not allowed and curtailment compensation is very low[2], therefore in the Spanish case, it exists volume risk for intermittent RES-E (financial risk associated to the energy that cannot be fed into the system), which was one of the reasons for the priority dispatch rule.

6.3 Support schemes

The support schemes give different levels of market risks exposure to intermittent RES-E. In general terms, intermittent RES-E need some support in order to be profitable, at least in the short-term. In Europe, support schemes vary among the different countries, not just by the amount of the subsidy, but also by the mechanisms, the responsibilities for market parties, the exposure to market prices and the risk sharing [35].

There are different ways to subsidize renewable sources: through indirect and direct methods [134]. The first ones refer to implicit payments (shadow connection, R&D subsidies, imbalance exemptions). An example of these indirect subsidies is the exoneration of balance responsibility. Additionally, exemptions of congestion costs and grid losses are under indirect methods. These exemptions do not give location signals to market participants, and they can subsidize also conventional generators.

Batlle et al. [134] suggest for intermittent RES-E a feed-in tariff (FiT) scheme to avoid problems of market power (infra-marginal capacity) for large producers that have in their portfolio intermittent RES-E and other energy sources, as intermittent RES-E cannot decide when to produce as it depends on meteorological conditions. Therefore, intermittent RES-E cannot decide when to produce and react to market

[2]Notice that in case of the day-ahead price is zero, there is not compensation.

prices accordingly. This is true under the priority dispatch rule. Without this rule, under negative prices, intermittent RES-E will not produce their maximum power if prices reach very negative values (higher than the support schemes). Batlle et al. [134] recommend full allocation of balance responsibility to intermittent RES-E, which incentivizes intermittent RES-E to improve power forecasts. In contrast with Batlle et al. [134], the European Commission [35] recommends feed-in premium (FiP) over FiT for technologies that are approaching maturity. The Commission does not make distinction between sources that are dispatchable and those that are not. The Commission implicitly considers that FiP to non-dispatchable sources incentivizes these sources to reduce their output in case of negative prices.

The support schemes are strongly related with other market regulations such as curtailment compensation schemes, which is an issue that has not been addressed by the Commission or the literature.

Particularly, in Spain before 2013, all intermittent RES-E could choose between FiT and FiP. The FiP was bounded by price caps and floors [135]. From 2013, although generators could still choose between the feed-in tariff scheme and the market option, the Spanish government [53] removed the premium above the market price. For this reason, in 2013 all renewable sources moved to the FiT. The disadvantage of this new regime is that it does not incentivize intermittent RES-E to reduce their generation in case of low market prices, specifically to those that are dispatchable[3].

6.4 Existence of negative prices

The existence of negative prices in the electricity market represents the inflexibility of supply, demand and grid. Additionally, negative prices send investment incentives to increase flexibility: investment in storage facilities, demand response, electric vehicles, investments in flexibility of generation units, among others. Some of the reasons for conventional generators to bid negative prices are [136]: the plant operators are not willing to ramp-down due to high start-up costs or opportunity costs (plants cannot ramp-up rapidly after an event of negative prices). Furthermore, market parties might have obligations in other markets such as in ancillary services. Negative prices occur also due to the lack of grid capacity which limits the transport of low marginal cost energy to places where it is less efficient or less profitable [137]. Investments in flexible solutions will eventually increase prices until the marginal cost of the flexibility equals the marginal benefit (under perfect competition assumption).

Negative prices allow to discriminate among different levels of inflexibility in an economic manner, as different generation units might be able to decrease generation for certain hours with different price levels, depending on their opportunity costs. The same argument is true for investments on generation flexibility or demand response.

[3]In 2014, it is expected that the Spanish Government approves changes in the support schemes based on revenues from market sales and additional payments that guarantees a fixed remuneration of renewable investments of 7.5% before taxes [55].

Therefore, negative prices that represent the system flexibility should be encouraged to send correct market price signals. Negative prices should be also allowed at different markets or time frames: day-ahead (DA), intraday (ID), balancing, congestion management, etc.

A price floor of zero implies a deadweight loss (a loss of economic efficiency). Demand might be able to react to negative prices, and it can be translated from other hours where there are positive prices.

The elimination of price floor of zero represents a change in market parties' surpluses between flexible and inflexible market parties. The effect on IES depends on the support schemes and compensation in case of energy curtailment. Additionally, the existence of negative prices might change the bidding strategies of thermal power plants in other hours to recover the possible costs when negative prices occur, and this can be translated into higher bid prices in other hours. The net effect for market parties is probably case-specific and it depends on the market parties behavior.

There is also a dynamic effect regarding negative prices; they are expected to occur less frequently in the long term. Demand, investments on flexibility or energy storage facilities will react to negative prices. Negative prices work as short-term signals to realize those changes. In countries with pumping hydro, those units can be used to increase demand in periods with high intermittent generation.

In case negative prices are not allowed, the TSO has to take more actions to deal with situations of tight system conditions, for example, to decrease generation output. An additional problem of zero price floors is how the TSO can discriminate among different inflexibilities that can lead to inefficient merit order effects. ENTSO-E [138] encourages the inclusion of negative prices in all the energy markets (day-ahead, intraday, balancing).

6.4.1 Negative prices in Europe

Negative prices are allowed in some European Power Exchanges (see Table 6.1). However, markets such as the Iberian, do not allow them. Negative prices would be especially beneficial in countries such as Spain and Portugal, with high wind penetration levels. In Spain, intermittent RES-E under FiT are dispatched at zero price in the wholesale market and they have priority dispatch. Until mid-2009, wind power curtailment was provoked by grid congestions or voltage dips. Since then, curtailments have happened mainly in off-peak hours, due to low demand and high wind generation [139].

Table 6.1: Minimum price limits in European energy markets

Country	**DA (€/MWh)**	**ID(€/MWh)**
Belgium	-3000	-99999
Germany & France (EpexSpot)	-3000	-9999
Netherlands	-3000	-99999
Nordic Region (Nord Pool)	-200	-99999
Spain & Portugal (Mibel)	0.01	0.01

In Germany, since September 2008, the power exchange allows negative prices [140]. Since then, the DA market has not been cleared, in some hours, due to high wind and low demand. In Germany, when negative prices occur in EPEXSPOT market, a second call is run. The TSOs can deviate from the obligation to sell all possible power and limit bids negative prices from renewable sources. The price limit can fluctuate in the range of -150 €$/MWh$ to -350 €$/MWh$ [141].

In most of the Northern European Power Exchanges the minimum ID price bound may reach extremely low prices, for Germany and France market is -9999 €$/MWh$. In Netherlands, Belgium and the Nordic region, the intraday prices can reach values of -99999 €$/MWh$.

Table 6.2 shows the number of hours with negative prices in the different markets for Denmark and Germany (two of the countries with wind power production and which allow negative prices).

Table 6.2: Hours with negative prices in Denmark and Germany, from January 2011 until December 2013

Prices	**Denmark West**	**Denmark East**	**Germany**
Day-ahead	87	75	119
Intraday	21	20	132
Positive imbalance	262	189	4600*
Negative imbalance	64	52	4600*

*Hourly average prices.

The Spanish market does not allow negative prices in any market. In the period from January 2011 to December 2013, the Spanish market had 554 hours with zero prices in the day-ahead market and even more hours with zero prices in the intraday markets and imbalance prices. Table 6.3 shows the distribution of zero prices in different markets for Germany, Spain and Denmark. It can be assumed that, in some hours, the price equilibrium in Spain should have been set at negative values, if they were allowed.

Table 6.3: Hours with zero price in Denmark, Germany and Spain, from January 2011 until December 2013

Prices	Denmark West	Denmark East	Germany	Spain
Day-ahead	5	4	4	554
Intraday	5	7	0	3083
Positive imbalance	102	87	4*	1369
Negative imbalance	4	3	4*	368

*Hourly average prices

Negative prices play an important role in the balancing market and in order to deal with predictability aspects of intermittent RES-E. When less generation is scheduled in the day-ahead and intraday markets and there is high generation from intermittent RES-E , downward regulation is activated to maintain system balance. Negative prices for downward regulation occur when thermal plants are willing to pay for decreasing their output. Negative prices can also occur when renewable sources pay back part of the support schemes to generate more than scheduled. If negative prices are not allowed in the balancing markets, it is not possible to distinguish by price signals between different levels of inflexibility and between different technologies. The lack of negative prices increases disputes between the SO and market parties that do not want to reduce their generation, for example as expressed by the Spanish Wind Association [142]. Furthermore, it increases the need of administrative actions carried out by the SO.

In the European context, different price floors in the markets could lead to inefficiencies. For instance, one country with a price floor of zero can have an excess of generation and curtails renewable energy, but at the same time, imports from neighboring countries with lower price floors (higher negative prices in absolute terms). This has been reported between Denmark and Germany [143]. In addition, it is also expected between countries that have price floors of zero (Spain) and neighbor countries with negative prices (France).

6.5 Intermittent RES-E curtailment and compensation schemes

The inclusion of negative prices in the different markets could reduce the need of energy curtailment. However, curtailment of intermittent RES-E can even occur for security reasons, operation and maintenance of the grid or because investments in flexibility, demand response and grid investments might take time[4]. Therefore, the concern is whether intermittent RES-E should receive any compensation for those

[4] In some cases, also it might be more efficient to have intermittent RES-E curtailment than expand the grid or invest in flexibility

times when they cannot feed all energy into the grid and IES are able to generate more.

Different curtailment compensation schemes have been applied in different European countries (specifically to wind power, as it is not dispatchable and it could be generated in low demand periods).

6.5.1 Wind power curtailment compensation schemes in Europe

Table 6.4 shows different wind power curtailment compensation schemes in different countries and the costs that wind power producers (WPPs) face in comparison with their opportunity costs (the support scheme that they would have received if they were not curtailed).

Table 6.4: Compensation schemes for wind power curtailment

Compensation	Losses for wind power	Countries where it is applied
Opportunity cost	No Losses	Denmark
		Belgium (after 60% of offshore wind output)
		Germany after 2011
X% DA price	(1-x%) DA price+Premium	Spain (x=15%)
DA prices	Premium	Sweden
		Ireland
		Denmark, for specific offshore wind farms
X%(DA price+Premium)	(1-X%) (DA price+ Premium)	Germany. Transpower area (now TenneT) before 2011.
Bilateral contracts	Depends on the price agreed	UK
No remuneration	DA price+ Premium	Germany, before 2009
		Spain, programmed curtailment before DA market
		Belgium, offshore wind up to 60% in winter

In Denmark, wind power curtailment has been used few times in the recent years [144]. The Danish TSO (Energinet.dk) compensates the WPPs for the loss of revenues. The regulation of curtailment compensation is applied to offshore wind farms that have been built by a tender process, as these sources are not granted with priority dispatch [145]. The first wind farm under this scheme is Horns Rev 2. Downward regulation from wind turbines might be used when it is needed to ensure the security of the system, or if it is socially optimal to do so. For an offshore wind farm (Anholt), which is in operation from September 2013, if there is congestion of the grid and the spot prices become negative, no subsidies are provided for a maximum of 300 hours [144].

In Germany, according to the German Renewable Energy Act (EEG) amendments of 2008, electric power facilities with over 100 kW capacity will be subject to forced curtailment of power production as grid bottlenecks occur. According to the revised regulations, grid operators will need to pay a compensation for generation capacity left unused due to grid management and curtailment procedures. As well, wind turbines, installed before 2009, must be retrofitted so generation can be curtailed at a TSO′s request. The TSOs may recover curtailment costs from customers, but it is necessary to demonstrate that all possible measures to optimize, improve and expand network capacity were taken before undertaking curtailment. However, the amount at which facilities are compensated from energy being curtailed was not specified by law. The German wind association, Bundesverband Windenergie, negotiated an agreement with Transpower[5], one of four transmission grid operators in Germany, in order to pay the electricity tariff rate for 90% of the lost revenues for the curtailment duration [146].

The German Federal Network Agency (Bundesnetzagentur) launched in August 31, 2010 a public consultation "Guidance on renewable energy feed-in management". In case of overload or congestions of the grid, the network operators could reduce output from renewable sources, CHP and gas mine facilities. However, they are obliged to compensate for the energy that is not feed-in due to grid congestion or security reasons. As a result of the public consultation process, it was agreed to compensate WPPs for loss of revenues [147].

In Great Britain, curtailment compensation is regulated from June 2010 [148]. Under this regulation, the payments for WPPs will be determined after the event. The volume that should be compensated will be determined according to the wind speed and output profile provided by the supplier and verified by the TSO. The curtailment price (utilization price) is agreed on a bilateral basis. The payment will be realized the following month. On 5/6th April 2011 and on 10-13th September 2011, National Grid required curtailing wind generation in Scotland due to local constraints. During those hours, National Grid paid high prices to decrease generation [111].

In Ireland in 2012, 2.1% of available wind energy was curtailed, approximately 80% of this was caused by system wide reasons, whereas the remainder was a result of local network constraints [143]. Wind producers that provide downward regulation will be remunerated by the day-ahead price; but not for the support scheme above that price [139].

In Sweden, wind power might be reduced due to grid congestions. WPPs will be compensated with the corresponding day-ahead prices [149]; therefore, there is a lost for WPPs equal to green certificates' price, which is above the day-ahead price.

According to De Vos and Driesen [150], Elia (the Belgian TSO) has the possibility to curtail up to 60% (in winter time) offshore wind power without compensation in order to guarantee the security of the grid. Above that percentage, the TSO has to compensate the loss of green certificate remuneration.

According to Eclareon [132], in some European countries no regulation about curtail-

[5]Currently TenneT TSO GmbH

ment compensation exists or it is difficult to apply, such as in Belgium, Italy, Malta, Poland or Portugal. On the other hand, excessive curtailment has occurred in Bulgaria, Greece, Spain, Italy and Malta. In other countries, curtailment is expected to occur in the future in Cyprus, Estonia and Great Britain.

6.5.2 Considerations for intermittent RES-E curtailment compensation for intermittent RES-E in the Spanish case

In Spain, energy curtailment is compensated by 15% of the day-ahead prices in case they occur in real-time [133]. The Spanish Wind Energy Association (AEE) has argued that successful integration of wind power in Spain has lead to easy curtailment of this technology. From January 2013 to April 2013, the Spanish SO (Red Electrica) curtailed 850 GWh with economic losses from these actions were approximately €83 million [142]. AEE signaled as part of the reasons for this massive curtailment is the inflexibility of nuclear power and combined heat and power (CHP), which covered more than 30% of hourly demand and nearly 15% of daily consumption. This could be partially due to zero price floors. In case of energy curtailment, this is done using a pro rata criterion [46].

The Spanish Wind Energy Association has asked for compensation for wind power curtailment (as it is done in Germany or Texas) [151]. However, if curtailment compensation was not considered at the time intermittent RES-E were installed, then it may not be justifiable to compensate them because they could have foreseen the risk when intermittent RES-E entered in the market.

In Spain, the SO has to propose to the Government grid expansion plans if curtailment of non-dispatchable energy sources occur more than three times a month or more than 10 times a year REE [152]. However, such expansion might not be economically optimal as grid costs can be significantly higher than the potential costs of renewable curtailment. Grid expansion plans become more difficult to predict, among other reasons, because different storage possibilities can be integrated in future electricity systems.

The introduction of negative prices in all the markets is expected to reduce intermittent RES-E curtailment. Furthermore, negative prices contribute to reduce discrimination problems among intermittent RES-E installations. When negative prices are not allowed, and there is no compensation or the compensation is a percentage of the support schemes or DA prices, it might give the incentive to the TSO to curtail oldest units as they usually have higher support schemes (they have been built in initial phases of the technology development). Negative prices are also necessary to reflect the needs of transmission updates or any alternative storage facility.

When negative prices are present in all the markets, for the remaining cases of intermittent RES-E curtailment, it can be signaled the following benefits of curtailment compensation for intermittent RES-E (especially wind):

- It decreases investment risk and, therefore, the capital requirements. Otherwise, it is necessary an increase in the support scheme provided to intermittent RES-E.
- It puts a cost for curtailment and that cost can be included when alternatives for curtailment reduction are considered.

However, there can be some cons of curtailment compensation for intermittent RES-E:

- If there is curtailment compensation, there is an incentive for intermittent RES-E to overbid in the energy markets when curtailment is expected. To reduce this incentive, the TSO might ask those units that it expects to have this strategy to produce at their bid quantity, and in case they cannot fulfill their bids the imbalance price should reflect the balancing costs (including the location consideration). Imbalance prices are essential to counteract to this incentive and also it gives incentives to improve forecasts and the preventive maintenance scheduling of intermittent RES-E.
- With full compensation of opportunity costs, there is no incentive to install new capacity in places where there is enough transmission capacity. Therefore, curtailment compensation should give locational price signals, for example, by not compensating for 100% of the opportunity costs, but a certain percentage, for instance 90% as in Germany before 2011. This encourages intermittent RES-E to be installed in places where there is enough grid capacity. The exact percentage might be studied in detail. Klinge Jacobsen and Schröder [153] argue that an agreement on curtailment levels should be specified before connection and it should be supervised by regulators based on network reference models. Beyond certain levels compensation should be given.

Any payment for curtailment should be reflected in market prices, such as balancing prices, which incentivizes flexible solutions to avoid curtailment. The choice of a curtailment compensation scheme will depend on the risk sharing between intermittent RES-E developers and the government (consumers). The lower the amount of curtailment compensation, the higher the incentives to install new installations in places where the grid is stronger. With changes in the priority dispatch rule or in countries where negative prices are not applied, curtailment compensation will increase even more its importance, also with higher intermittent RES-E penetration levels. If the priority rule is not in place, the support scheme will represent a floor for the curtailment price.

6.6 Evaluation of alternatives of the priority dispatch for Spanish 2020 scenario

This section evaluates the current regulations of priority dispatch in Spain with price floor of zero with an alternative option of not applying the priority dispatch to intermittent RES-E and allowing negative prices. This evaluation has been done for mainland Spain 2020 scenario. The model used for this evaluation corresponds to the ROM model (Reliability and Operation Model for Renewable Energy Sources), which has been developed by the Institute for Research in Technology at Comillas Pontifical University and widely explained in MERGE Project [154] and TWENTIES Project [115]. It mainly consists in a mathematical programming for minimizing the daily system operation costs. It includes a simulation process to evaluate the system in real time. The first step of the ROM model determines the initial program for the generation units, as a result, the economic dispatch based on the day-ahead demand and wind forecasts is obtained. In the second step the simulation process is performed and the generation program is affected by changes in the random variables (the model corrects for demand and wind forecast errors or thermal outages).

The following changes in ROM model have been included to compute the effects of changes in the priority dispatch rule and the elimination of zero price floor:

- The differentiation between existing intermittent RES-E installations and expected investments from intermittent RES-E.
- The effect of negative prices and penalizations for intermittent RES-E curtailment based on different levels of opportunity costs.
- The possibility of demand response for both energy market (day-ahead market) and provision of balancing services.

Some of the main results provided are: system thermal costs, curtailment of intermittent RES-E, revenues of intermittent RES-E (existing and expected) and costs for consumers.

The model considers curtailment due to low demand and high generation from intermittent RES-E, ramping limitations or security reasons. Other reasons for intermittent RES-E curtailment are not considered, such as network limitations or exercise of market power [153].

The input data of the model comes from public-available data from Red Eléctrica de España and the Spanish Regulator (Comisión Nacional de Energía)[6]). Future scenarios for intermittent RES-E have been collected from the intermittent RES-E deployment plan (Plan de Energía Renovables), approved by the Spanish government by the end of 2011 [155].

[6]Now Comisión Nacional de los Mercados y la Competencia (CNMC).

Table 6.5 shows the tariffs used for intermittent RES-E. The tariffs used for existing installations correspond to the total remuneration (in €/MWh) received by these units during 2013 and published by CNMC [156]. The forecast of costs reduction of are used to set lower tariff levels for the expected installations. IRENA [157] forecasts that the Levelized Cost of Energy (LCOE) for wind in Europe will decrease from 6% to 7% from 2011 to 2015. For PV, LCOE is expected to decrease dramatically by around 80% from 2011 to 2015 [158]. The expected cost reduction percentages from IRENA for wind and solar are applied to the current tariff levels to obtain an average tariff values for new installations.

Table 6.5: Tariffs assumed for renewable sources (€/MWh)

Installations	**Wind**	**Solar**	**Other IES**
Existing installations (before 2013)	82.0	326.0	105.0
Expected installations (after 2013)	76.2	65.2	105.0

The focus of the model is a cost minimization under perfect competition assumption. The model was run for the whole year 2020. It is solved using CPLEX under GAMS.

6.7 Results and discussions

This section presents the results of the ROM model obtained for mainland Spain for the 2020 scenario. Three cases are modeled:

- Current regulation. This case consists in a priority dispatch for all renewable sources. In this scenario, demand response is not included. In addition, in case of intermittent RES-E curtailment in real-time, curtailment is compensated with 15% of the day-ahead market price. As currently negative prices are not allowed, when the model computes negative market prices they are set at zero value.
- Proposed changes in the priority dispatch for Spain. This case consists in removing the priority dispatch rule for all the technologies and it includes negative prices. For this case, intermittent RES-E curtailment is penalized using the different support schemes, differentiated according to the technologies and if they are already installed or they are expected to be planned in the future. First, this case does not use demand response.
- The previous case including demand response (DR). DR is active in two forms. On one hand, demand is able to shift energy throughout the day. Energy consumption that is reduced in some hours must be recovered in others. The total energy consumption over the day remains the same. Demand shifting is limited to a certain participation of the demand side. As in Dietrich et al. [159], 8% of the total demand can be shifted in each hour with 7% limit for

peak shaving. The model decides to shift demand when this results in lower operational costs. This is the case when demand is reduced in peak hours and recovered in off-peak hours. This approach has been explained in detail in Dietrich et al. [159]. Demand is also capable to offer regulation reserves. So, in the day-ahead unit commitment, demand is able to offer reserve. In contrast to demand shifting, reserves for demand reduction and increase do not have to be recovered at another time, but reserve provision is also accounted within the 7% limit of demands that are flexible and can be used to either shift demand or provide reserves.

As shown in Table 6.6, thermal costs are slightly reduced with the proposed changes in the priority dispatch and demand response, in comparison with the other two scenarios. These results are expected, as demand will react to market prices to decrease the system cost. However, without the priority dispatch, curtailment of intermittent RES-E may increase. These cases occur when demand is low and intermittent generation is high. In addition, curtailment of intermittent RES-E occur in cases of ramping restrictions.

Table 6.6: Thermal costs and intermittent RES-E curtailment resulted from changes in the priority dispatch rule

Model Output	Current regulation	Proposal without DR*	Proposal with DR*
Thermal cost [€ m]	10792	10792	10765
Existing wind units' curtailment [GWh]	241.90	2.71	0
Existing solar units' curtailment [GWh]	15.03	0	0
Expected wind units' curtailment [GWh]	87.32	313.01	264.66
Expected solar units' curtailment [GWh]	5.01	135.46	101.16
Total intermittent RES-E curtailment [GWh]	349.27	451.18	366.69

*DR= Demand Response

As previously mentioned, in Spain, current regulation establishes a pro rata criterion to curtail intermittent RES-E [46]. This means that the reported curtailment should be equally distributed among all units, without given priority to the existing units. A negative side effect of this methodology is that new units receive distorted incentives to be installed in places where curtailment may be decreased and curtailment decisions are not reflected in prices.

Table 6.7 shows the distributional effects of changing the current priority design for intermittent RES-E. The current case is compared with the proposal with demand response. First of all, as negative prices are allowed, demand can react to this, with a total reduction of demand costs (marginal system price multiplied by demand) of around 3%. Second, as marginal prices decrease, in order to guarantee the same amount of remuneration to intermittent RES-E, the payments above the marginal prices need to increase by 8%. Third, the current regulations established curtailment compensation for 15% of the day-ahead market price if curtailment occurs in real-time. Therefore, the final consumers payments as a result of the sum previous costs decrease in 1.61%.

Table 6.7: Distributional effects resulted from changes in the priority dispatch rule

Costs / Revenues	Current case	Proposal with DR*	Change	Curtailment reward	Change
1. Energy cost	€ 29082.0 m	€ 28209.1 m	-3.00%	€ 28209.1 m	-3.00%
2. Intermittent RES-E cost	€ 4223.9 m	€ 4561.4 m	7.99%	€ 4561.4 m	7.99%
3. Curtailment compensation	€ 0.3 m	-	-	€ 24.0 m	6783%
4. Total demand Cost [1+2+3]	€ 33305.9 m	€ 32770.5 m	-1.61%	€ 32794.5 m	-1.54%
5. Existing wind units' revenues	€ 3927.7 m	€ 3947.4 m	0.46%	€ 3947.4 m	0.46%
6. Existing solar units' revenues	€ 3669.5 m	€ 3674.4 m	0.13%	€ 3674.4 m	0.13%
7. Expected wind units' revenues	€ 1887.9 m	€ 1874.4 m	-0.75%	€ 1892.5 m	0.21%
8. Expected solar units' revenues	€ 582.6 m	€ 577.3 m	-0.92%	€ 583.2 m	0.09%

*DR= Demand Response

The revenues for existing intermittent RES-E do not decrease, even without applying any curtailment compensation. This is because curtailment of these units decreases as a result of negative prices and demand response. On the other hand, new installations will face higher risk of curtailment, as they receive lower tariffs and they bid lower negative prices in the market (in absolute values). Although, this model does not represent the grid, new installations have incentives to be installed in areas where potentially curtailment could be reduced. However, curtailment compensation for new installations is an open aspect which affects the risk faced by owners of the installations. If curtailment compensation is not provided, then support schemes should increase to compensate for potential losses from curtailment. If new installations are compensated by 90% of the support schemes in case of curtailment, the same revenues are guaranteed for these units and consumers' costs are still lower by 1.54%, in comparison with current case.

6.8 Conclusions

According to the European Commission, the priority dispatch rule for renewable sources is no longer necessary. However, it has been already granted for existing units. In case it has to be changed there are different market design aspects that need to be considered. This chapter discusses some of those relevant aspects and measures the impact of them to the Spanish case study in the 2020 scenario.

The priority dispatch rule, as currently implemented in the Spanish market, does not eliminate the volume risk of renewable sources as they face curtailment costs with relative low compensation. The Spanish market currently has a price floor of zero in all the markets. Thus, zero prices appear more frequently than in other markets with high penetration of intermittent RES-E.

The lack of negative prices has important implications for the system efficiency.

First, it does not allow the TSO to discriminate between different levels of inflexibilities, from thermal units, demand or transmission capacity. In case of need of curtailment of intermittent RES-E, the Spanish System Operator uses a pro rata criterion for all installations. For new installations, investment signals are distorted, as new units do not face the proper market risks. In addition, storage facilities and demand response programs cannot respond to the proper price signals if negative prices are not allowed.

The operational model for the Spanish scenario shows that, by removing the priority dispatch and allowing negative prices, the costs for consumers are reduced and revenues of intermittent RES-E are almost not affected in comparison with the current situation. This implies a gain in economic efficiency for the whole system. In addition, with the proposed changes the short-term price signals of inflexibility are reflected. Future intermittent RES-E installations are expected to receive lower levels of support schemes than existing ones because of technological improvements. With negative prices, existing installations can bid higher negative prices (which correspond to the support schemes with negative sign).

The results show that with negative prices and without the priority dispatch, curtailment for existing units is reduced and the total revenues for these units could increase slightly. New installations will face more curtailment with negative prices, even by considering demand response. Although the model does not represent the grid, future installations, by facing higher curtailment risk, have incentives to locate in areas where potentially curtailment could be reduced. In order to reward for higher curtailment risks, new installations may require a financial compensation, but this compensation should give locational signals (by not compensating fully the support schemes). If compensation is not provided, higher amount of support schemes might be required.

Chapter 7

Impact of European balancing rules on wind power bidding strategies

7.1 Introduction

Wind power has specific rules with respect to other generation units. Firstly, it usually receives support schemes in order to make it competitive at the current price levels. Secondly, wind power may also be subject to specific balancing rules, for instance, to what extent it is responsible for the energy committed in the different energy markets, put forward by the limited capability to forecast its energy. Additionally, market designs were usually created for conventional generation units. For example, the day-ahead (DA) market is usually liquid; and the market clearing takes place the day before delivery, in order to program the dispatch of conventional generation units. However, at DA gate-closure, there is still a lot of uncertainty for wind power due to meteorological data that affect its predictability. On the other hand, intraday (ID) markets, which have gate closure times closer to real time, are less liquid [19].

Balancing rules can affect other market regulations. For example, the European Commission [35] has pointed out that the costs of market integration, such as balancing costs, need to be considered to compute the support schemes interactions with electricity markets. Therefore, the economic impact of balancing costs needs to be considered for well-designed of support schemes.

The contributions of this chapter are: first, to describe the impact of different balancing designs in the allocation of balance responsibility to wind power and the design of the imbalance pricing. Second, to explore the advantages and disadvantages of those designs related to incentives for market parties and efficient inclusion of wind power in the electricity market. Third, to develop a methodology that provides a quantitative assessment of different balancing designs and the economic implications for WPPs. Fourth, to apply the proposed methodology considering market data from different European countries (Belgium, Denmark, Germany and the Netherlands). These countries have been chosen because they apply different balancing rules to wind power. In addition, a significant increase of wind power is expected in these countries in the coming years and decades (in which offshore wind will have an important share). Finally, from the quantitative analysis and based on the literature review, some policy recommendations are derived related to the design of balancing arrangements in relation to wind power.

This chapter continues as follows: Section 7.2 describes the regulatory context for the allocation of balance responsibility and the imbalance pricing design in Belgium, Denmark, Germany and the Netherlands. Section 7.3 describes the methodology used and the data for the quantitative evaluation of the different balancing rules. Section 7.4 presents the model results. Finally, Section 7.5 provides the main conclusions and gives some policy recommendations.

7.2 Regulatory context

This section describes the last changes in the balancing rules applied in the four analyzed countries with respect to the allocation of balance responsibility to wind power and the imbalance pricing designs. Both regulations have been significantly modified during the last years in these countries, which reflects the importance of balancing rules for policy makers.

7.2.1 Balance responsibility

Among the European countries, there is not a uniform way to allocate balance responsibility to WPPs. Some countries give full responsibility to WPPs, as any other market party (i.e., the Netherlands, Sweden, U.K.).

In Belgium, the responsibility is shared between WPPs and the TSO, with tolerance margins for offshore wind farms of 30% of final energy imbalances [160, 161]. Therefore, if the energy imbalances are within those percentages, positive imbalances are remunerated at 90% of the DA price and negative imbalances pay 110% of the DA price.

In other countries, WPPs are exempted from imbalance costs (i.e, do not have balance responsibility), in this case, the balance responsibility resides with the TSO (Germany before 2012, France and Ireland). In Germany before 2012, the TSOs, aside from being responsible for imbalances from Renewable Energy Sources for Electricity (RES-E), they sold RES-E energy in the DA and ID markets. From January 2012, RES-E additionally have the option to sell their output to the market and receive a premium on top of the market price, which represent the difference between the feed-in tariff (FiT) and the ex-post average price. RES-E can opt for direct selling (marketing) all the generation, or part of it, in the market or bilaterally. The premiums applied are calculated each calendar month retrospectively [162]. In addition to the market premium, WPPs also receive a so-called management premium, which covers the costs of direct participation in the market. For 2012, this value was set at 12 €/MWh for wind and solar [61]. As of 2013, the management premium was reduced to 7.5 €/MWh for solar and wind (both onshore and offshore), see Table 7.1.

Table 7.1: German management premium for wind and solar (€/MWh)

Year	Renewable Energy Act 2012	Management Premium Ordinance enacted at 29.08.2012	
	All installations	Remote control installations	Other installations
2012	12	-	-
2013	10	7.5	6.5
2014	8.5	6	4.5
From 2015	7	5	3

*Based on Gawel and Purkus [61].

Denmark has changed the regulation regarding the allocation of balance responsibility: for old wind farms (built before 2003), the TSO is responsible for imbalances, for units built afterwards balance responsibility is allocated to WPPs, which receive an imbalance subsidy of 2.69 €/MWh, ($1EUR = DKK$ 7.45) [163]. This subsidy is applied to onshore wind, and to those offshore wind farms that are not covered by tender procedures. Offshore wind farms covered by tenders are fully responsible.

The pros and cons for allocation of balance responsibility to RES-E have been discussed in the literature. For instance, Klessmann et al. [164] discussed the advantages and disadvantages of exposing renewable energy to market risk. They argue that the allocation of balance responsibility to WPPs increases the risk exposure and consequently the financial requirements. In addition, it favors large players with diversified portfolios and strengthen the role of intermediaries. On the other hand, the allocation of balance responsibility to WPPs incentivizes them to forecast generation more accurately. If WPPs are exempted from balance responsibility, the TSO has to forecast and schedule wind generation. In this case, the challenge is to incentivize TSOs to improve forecasts.

Hiroux and Saguan [33] agree that the allocation of balance responsibility to WPPs increases the risks and the transaction costs, but they reduce over time. Moreover, according to the Hiroux and Saguan [33], the WPPs have most knowledge about their turbines' availability and other detailed information can increase the prediction accuracy. Rivier Abbad [50] favors full allocation of balance responsibility to WPPs, which incentivizes the forecasting tools to reduce imbalance costs.

The Council of European Energy Regulators (CEER) [165] suggests that balance responsibility should give the same incentives to wind power, as to any other power unit. By doing so, WPPs are incentivized to improve forecast tools and reduce imbalances. Additionally, geographical aggregation might be useful to reduce forecast errors. Most of the respondents to the Public Consultation of CEER agree that allocation of balance responsibility to WPPs helps to solve congestions, limit the risk of gaming, improve forecasting and usability of wind energy.

ENTSO-E [138] argues that making RES-E generators responsible for balancing reduce the needs for the TSOs to balance in real-time, as it encourages market parties to use market mechanisms in different time frames to manage their imbalances. The allocation of balance responsibility to market parties also enhances the overall efficiency, reduces the total customer costs and restricts the role of the TSOs to deal with the remaining system imbalance [138]. ACER [5] suggests that intermittent RES-E shall not receive any special treatment for imbalances and they shall be financially responsible for imbalances.

This chapter assesses the impact of the allocation balance responsibility to wind power on bidding strategies in the considered countries. From the analysis, it can be assessed to what extend the allocation of balance responsibility to WPPs is related to other balancing regulations such as the imbalance settlement. Therefore, depending on the interactions of balancing rules, WPPs would reduce energy imbalances if they are fully balance responsible.

7.2.2 Imbalance settlement

Vandezande et al. [21] argues that single pricing is a zero-sum game for the TSO; while, in the dual pricing, there is a gain, which usually is redistributed to the market by the reduction of transmission tariff. Dual pricing has some drawbacks [131, 166]: a transfer of money from inflexible generation units to average users, which puts in disadvantage small players that do not have a generation portfolio to manage their imbalances (especially if there is not a liquid ID market). Furthermore, Saguan [131], Vandezande [166] argue that when dual pricing includes additional penalties, it usually affects higher negative imbalance, leading to over-contract in the DA or ID markets.

The imbalance pricing mechanisms differ among countries. Germany, the Netherlands and Belgium (after 2012) apply single pricing. On the other hand, the Nordic countries (for generation units), France, Great Britain and Spain apply dual pricing (although Great Britain decided to move towards single pricing). Appendix D explains in more detail, the imbalance pricing in Belgium, Denmark, Germany and the Netherlands.

Imbalance pricing in the Netherlands

The average price difference between IM prices for short and long positions in 2010 was around 2 €/MWh, while for 2011 and 2012 it has increased to around 8 €/MWh. The IM price difference corresponds to the regulation state 2, when different IM prices are applied for long and short positions.

Imbalance pricing in Belgium

Due to dual pricing applied in 2010 and 2011, the difference between IM prices for short and long positions for those years was quite large, around 30 €/MWh. Therefore, energy imbalances in Belgium, before 2012, were strongly penalized.

In January 2012, imbalance pricing changed to single pricing (based on the marginal prices of downward and upward activated bids) with an additional incentive applied in case of large system imbalances [167]. With this change in imbalance pricing, for 2012, the average IM price for short positions was 54.05 €/MWh (the average DA price is 45.85 €/MWh), while the average IM price for long positions was 51.84 €/MWh. The spread between DA prices and IM prices has decreased substantially from previous years due to changes in imbalance pricing.

Since January 2012, the Belgian TSO (Elia) updates the system imbalance every 2 seconds, and every quarter hour the resulting IM prices [168]. This publication allows market parties to react to the system imbalance in real time in case it is favorable for them.

7.2.2.1 Imbalance pricing in Denmark

Denmark is divided in two bidding areas: East and West. The East part is synchronous with the Nordic region, while the West part is synchronous with Continental Europe. For simplicity, the information presented in this chapter corresponds to Denmark West (DK1). As a result of dual pricing, the difference between IM prices for short and long positions in both regions varies from around 10 €/MWh to 15 €/MWh.

7.2.2.2 Imbalance pricing in Germany

Germany applies single pricing. The IM price corresponds to the average costs of activated reserves and BSPs are paid their own bid price (pay-as-bid) [117]. Since June 2010, the German IM prices are computed for the whole country (a detailed description of the German imbalance pricing can be found in Appendix D). Due to single imbalance pricing applied in Germany, the resulting IM prices are always the same for short and long positions.

Table 7.2 presents the balancing designs of the discussed European countries. Table 7.3 shows the average DA and IM prices for 2010, 2011 and 2012. As shown in Table 7.3, in the case of dual pricing (Denmark, and Belgium before 2012), differences between IM prices for short and long positions are high.

Table 7.2: Balancing designs in Belgium, Denmark, Germany and Netherlands

Country	Balance Responsibility for wind power	Imbalance settlement
Belgium	Tolerance margins: 30% offshore	Dual pricing (before 2012), after 2012, single pricing
Denmark	Imbalance subsidy	Dual pricing
Germany	Imbalance subsidy (after 2012)	Single pricing based on average balancing cost
Netherlands	Full-responsibility	Single pricing with regulation states

Table 7.3: Yearly average day-ahead and imbalance prices 2010-2012

Country	2010 Prices €/MWh			2011 €/MWh			2012 €/MWh		
	Day-ahead	Imbalances		Day-ahead	Imbalances		Day-ahead	Imbalances	
		Short	Long		Short	Long		Short	Long
Belgium	46.30	60.58	29.02	49.37	62.73	29.22	45.85	54.05	51.84
Denmark (DK1)	46,49	50. 8	40.82	58,87	64.36	51.44	43,12	47,90	38.26
Germany	44.48	43,96	43,96	51.18	32.96	32.96	42.27	46.48	46.48
Netherlands	45.37	45.54	43.37	52.07	53.85	45.80	48.05	54.10	46.58

7.3 Methodology

The objective of the methodology used is to evaluate both different balance responsibility schemes and imbalance pricing rules from the different countries in a real offshore wind farm. In general terms, market outcomes are simulating by connecting an offshore wind farm to different countries.

The case study and the methodology applied have been extensively described in Chapter 3. However, this chapter adapts this methodology to the balancing rules of each of the countries considered. Some of the possible extensions of the model described in Chapter 3 can be also applied to the adaptations presented in this chapter.

In general terms, the methodology consists in (see Figure 7.3.1): first, based on past data, the description of uncertainty of market prices (DA, ID, IM) from the different countries. In order to achieve this, a time series model is used (see Section 7.3.2). Then the prices' uncertainties are represented through simulations. Finally, price simulations and energy forecast for the offshore wind farm are included in a stochastic optimization model, which maximizes the profits of the offshore wind farm from the participation in both DA and ID markets and decides the final energy delivered. The stochastic optimization has three stages. The first stage is the DA market. The results of the DA model with the updated energy and prices simulations are included as inputs for the ID model. Based on both markets results and on IM prices, the model determines the final energy delivered.

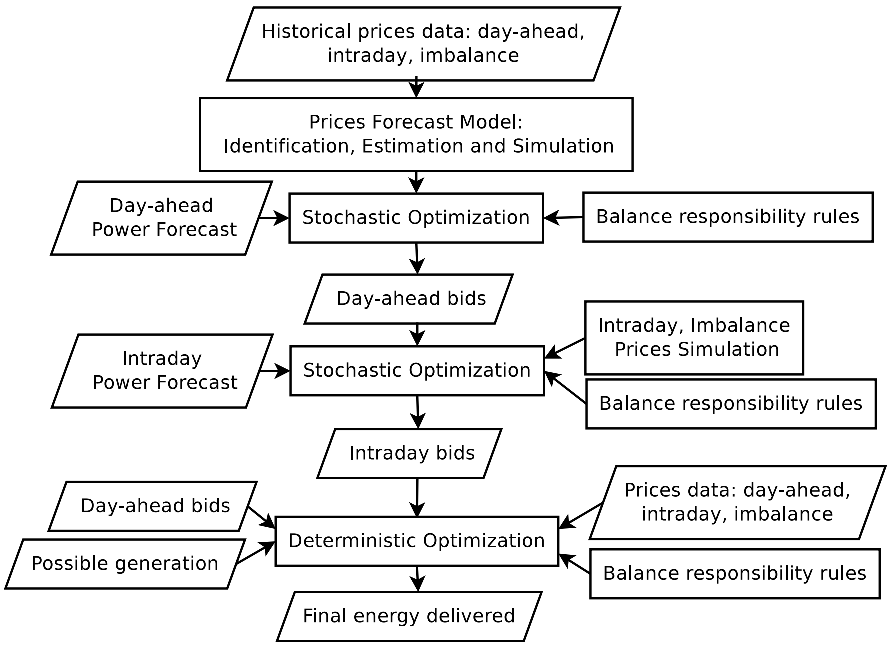


Figure 7.3.1: Modeling process

For the purpose of this chapter, support schemes are not considered, in order to isolate the effect of the imbalance costs from the different support schemes. However, they can be easily incorporated in the formulation as in the analyzed countries offshore wind farms receive a feed-in premium on top of the market prices.

The model assumes that the WPP does not affect market prices (the WPP is price-taker). For ID prices, the volume-weighted ID prices are used. Market prices and the wind energy data are assumed independent stochastic processes. For simplicity, the wind power producer is assumed risk neutral.

The optimization model is written in GAMS and solved using CPLEX 24.1.1 with a tolerance margin of 2%.

7.3.1 Mathematical formulation

The mathematical formulation is adjusted for the participation of WPPs at the different stages: DA market, ID market and finally, based on the results of these two markets, the computation of energy imbalances. The formulation is adapted to the allocation of the balance responsibility of the considered countries. The next subsections explain the mathematical formulation applied to the different countries.

In a continuous ID market, such as the ones in place in the studied countries, market participants can see the previously submitted bids by other market participants at any time. As it is assumed that the wind farm submits bids to the intraday market one hour before real-time, ID prices are assumed known.

The Netherlands, Belgium and Denmark have ID markets with low volumes. In 2012, the percentage of hours with market results was 20%, 22% and 73%, respectively. Consequently, for these countries, at the DA stage, the ID market is not considered. At the ID stage, bids are cleared only if there are market results for the corresponding hours.

The Netherlands has been publishing the system imbalance and the price of the last activated reserve every minute, while Belgium does it every two minutes since January 2012. Denmark publishes the IM prices of the previous hour in the NordPool platform. Consequently, for these countries the IM prices are assumed known in real-time. So, wind generators can take the decision of not generating all possible energy and voluntarily deviate from the energy schedules in case of negative IM prices for long positions. By doing this, market parties help to decrease the system imbalance.

7.3.1.1 Belgium

For Belgium, two cases are considered, with and without tolerance margins. According to De Vos et al. [160] and CREG [161], for an offshore wind farm, when imbalances are lower than 30%, the IM price for long positions is $0.9\lambda^{DA}$ and the imbalance price for short positions is $1.1\lambda^{DA}$. Therefore, energy imbalances are divided in two parts, those lower than 30% of nominated power, and those higher than 30% ($\Delta_{1h\omega}$). The whole formulation for the Belgium case is described in (7.3.1)-(7.3.19).

In the case of Belgium, Denmark and the Netherlands, ID bids in the DA stage are not considered, therefore, $P^I_{h\omega}$ can be replaced by zero in the formulation $\left(P^S_{h\omega} = P^{DA}_{h\omega}\right)$. The objective function of the model is described by (7.3.1), where the expected revenue is defined by $\xi\left\{R\right\}$. Notice that this formulation is nonlinear. However, it is converted into a mixed integer linear programming afterwards.

$$\begin{aligned}\xi\left\{R\right\} = \sum_{\omega=1}^{N_\Omega}\sum_{h=1}^{N_T} \Big(&\lambda^{DA}_{h\omega}P^{DA}_{h\omega} + \lambda^I_{h\omega}P^I_{h\omega} + 0.9\lambda^{DA}\left(\Delta^+_{h\omega}(1-\alpha) + 0.3P_{h\omega}\alpha_{h\omega}\right) \\ &-1.1\lambda^{DA}_{h\omega}\left(\Delta^-_{h\omega}(1-\beta) + 0.3P_{h\omega}\beta_{h\omega}\right) + \lambda^+_{h\omega}\Delta^+_{1h\omega} - \lambda^-_{h\omega}\Delta^-_{1h\omega}\Big)\end{aligned} \tag{7.3.1}$$

The power bids in the DA plus the ID markets are defined as $P^S_{h\omega}$.

$$P^S_{h\omega} = P^{DA}_{h\omega} + P^I_{h\omega} \tag{7.3.2}$$

The energy deviation function includes both imbalances which are higher or lower than 30% (7.3.3).

$$\Delta_{h\omega} = \left(P_{h\omega} - P^{S}_{h\omega}\right) = \Delta^{+}_{h\omega} - \Delta^{-}_{h\omega} \tag{7.3.3}$$

The sum of power sold in the DA and in the ID market must be positive and less than the installed capacity (7.3.4).

$$0 \leq P^{S}_{h\omega} \leq P^{max} \tag{7.3.4}$$

Equations (7.3.5)-(7.3.6) define the boundaries of the imbalances. At the DA stage, the expected energy imbalances have been limited to 35% of the possible imbalance the wind farm can have. These restrictions are relaxed for the ID and real-time stages.

$$0 \leq \Delta^{+}_{h\omega} \leq 0.35 P_{h\omega} \gamma_{h\omega} \tag{7.3.5}$$

$$0 \leq \Delta^{-}_{h\omega} \leq 0.35 P_{max} \left(1 - \gamma_{h\omega}\right) \tag{7.3.6}$$

Energy imbalances higher than 30% of the energy delivered are defined in (7.3.7)-(7.3.8).

$$\Delta^{+}_{1h\omega} = \Delta^{+}_{h\omega} \alpha_{h\omega} - 0.3 P_{h\omega} \alpha_{h\omega} \tag{7.3.7}$$

$$\Delta^{-}_{1h\omega} = \Delta^{-}_{h\omega} \beta_{h\omega} - 0.3 P^{max} \beta_{h\omega} \tag{7.3.8}$$

The energy imbalances variables have lower bounds equal to zero (7.3.9) - (7.3.10).

$$\Delta^{+}_{1h\omega} \geq 0 \tag{7.3.9}$$

$$\Delta^{+}_{1h\omega} \geq 0 \tag{7.3.10}$$

Additionally, only it is possible to have either positive or negative imbalances as shown in (7.3.11).

$$\alpha_{h\omega} + \beta_{h\omega} \leq 1 \tag{7.3.11}$$

The previous formulation (7.3.7)-(7.3.8) is non-linear because the product of two variables: $\Delta^{+}_{h\omega} \alpha_{h\omega}$, $\Delta^{-}_{h\omega} \beta_{h\omega}$. Therefore, a transformation is necessary to have a mixed integer programming (MIP). The transformation used has been proposed in Williams [169]. This transformation consists of changing each product of the two variables by a new continuous variable ($X_{h\omega}$) and ($Y_{h\omega}$) a set of constraints: (7.3.12)-(7.3.17).

$$-\Delta^{+}_{h\omega} + X_{h\omega} \leq 0 \tag{7.3.12}$$

$$-\Delta^{-}_{h\omega} + Y_{h\omega} \leq 0 \tag{7.3.13}$$

$$\Delta^{+}_{h\omega} - X_{h\omega} + P_{h\omega}\alpha_{h\omega} \leq P_{h\omega} \tag{7.3.14}$$

$$\Delta^{-}_{h\omega} - Y_{h\omega} + P^{max}\beta_{h\omega} \leq P^{max} \tag{7.3.15}$$

$$X_{h\omega} \leq P_{h\omega}\alpha_{h\omega}, \tag{7.3.16}$$

$$Y_{h\omega} \leq P^{max}\beta_{h\omega} \tag{7.3.17}$$

Due to low liquidity in the ID market, ID bids are limited to 10% of the wind farm capacity. In this way, bids are not expected to change the market price (7.3.18).

$$-0.1P_{h\omega} \leq P^{I}_{h\omega} \leq 0.1P_{h\omega} \tag{7.3.18}$$

A non-anticipativity constraint (7.3.19)-(7.3.20) must be added to the previous formulation, similar as discussed in Conejo [93]. In this formulation, the non-anticipativity constraint is necessary in order to ensure only one bid can be submitted to the DA and ID markets, irrespective of the wind power scenarios and prices scenarios.

$$P^{DA}_{h\omega} = P^{DA}_{h\omega'}, \forall h, \forall \omega\omega' \tag{7.3.19}$$

$$P^{I}_{h\omega} = P^{I}_{h\omega'}, \forall h, \forall \omega\omega' \tag{7.3.20}$$

7.3.1.2 Denmark

For the Danish case, the Belgian formulation is used without considering tolerance margins, then a positive imbalance is represented by $\Delta^{+}_{h\omega}$ and a negative imbalance by $\Delta^{-}_{h\omega}$. Additionally, the imbalance subsidy is added to the objective function in the different stages as: $2.69\left(P^{S}_{h\omega} + \Delta_{h\omega}\right)$.

7.3.1.3 Germany

The Belgian formulation is used without considering tolerance margins. In addition, at the day-ahead stage, ID bids are considered.

Similar to the Danish case, the German formulation includes the management subsidy in the objective function as: $12\left(P^S_{h\omega} + \Delta_{h\omega}\right)$. In the German case, it is difficult to predict IM prices, as the system imbalance and the IM prices are not published close to real time. This limits the possibility for wind farms to react to negative IM prices when there is an excess of generation (the system is long). For this reason, in the German case the wind farm delivers all possible generation.

The model assumes the wind farm is small and has no effect on market prices. In order to verify this assumption, the effect of additional energy imbalances is considered in IM prices. The German IM prices are computed using the balancing rules applied in 2012 and bid data of FRR and RR, as well the of activated reserves used for each of the German TSO. These data are available in the common German platform for the reserve procurement[1]. For this computation, deviations from merit order are not considered neither the non-transferable costs. These assumptions originated certain differences with actual IM prices, but they are on average for 2012 around 2 €$/MWh$. Based on computed IM prices, the effect of additional imbalances in IM prices of the wind farm are analyzed.

7.3.1.4 The Netherlands

Similar to Germany and Denmark, the Belgian formulation is used without considering tolerance margins. Chaves-Ávila et al. [81] use similar methodology but considering cross-border ID trading between the Netherlands and Germany.

[1] https://www.regelleistung.net/

7.3.2 Data description

Prices data for each of the countries for 2012 are used to compute the prices forecast and simulation. The prices data are publicly available in the corresponding power exchanges, except for the Netherlands, but the data were provided by the Anglo-Dutch energy exchange (APX) on request. Then, the stochastic optimization model is run for each of the countries for December 2012. The market prices for December 2012 do not significantly differ from those of the whole year, which make them representative.

The wind data and energy forecast correspond to the Windpark Egmond aan Zee, as explained in Chapter 3.

Price forecasting and simulation

The uncertainty modeling uses a Seasonal Autoregressive Integrated Moving Average (SARIMA) model, together with a GARCH model (Generalized Autoregressive Conditional Heteroskedasticity), in case the data present the patterns of a GARCH model [96]. The SARIMA model represents daily and weekly seasonalities of prices. This modeling is applied for DA, ID and IM prices for each country. Basically, based on past data, a price forecasting model and generate scenarios are applied, which represent prices uncertainties. The best-fitted models for the DA, ID and IM prices for all the countries are shown in Table 7.4.

The price forecasting follows these steps:

- Model identification. First, the time series are studied to stabilize the mean and the variance. To stabilize the variance, a logarithm transformation (Box-Cox transformation) of the series is applied. Then, the autocorrelation and partial autocorrelation functions are used to detect the autoregressive and moving average components of both seasonal and regular parts of the model.
- Model estimation. Different models are tested to detect which one adjusts better to the time series data. For this, the statistical significance of the coefficients, the Akaike and Bayesian Information Criteria are used. In addition, the autocorrelation and partial autocorrelation of models errors are tested to see if the model chosen is not misspecified. The estimation is performed considering 9 months with a validation period of 3 months. The final model chosen is the one with the lowest forecast error described by the Mean Absolute Error (MAE) computed for the validation period. The MAE is defined as: $MAE = \frac{1}{N}\sum_{i=1}^{N}|e_i|$ where e_i is the error in the period i, which means the difference between observed and forecasted values. Finally, the errors of the estimated SARIMA models are tested to find GARCH behavior.

  For those IM prices correlated with the DA prices (the Danish case), the DA prices are considered as exogenous variables (ARIMAX).
- Price simulation. Once the final model is chosen, a simulation of 1000 scenarios per variable is performed per each price series at DA and ID horizons.

The model identification is developed using IDAT software developed in Comillas University, while the simulation is carried out in Matlab using Matlab Econometrics Toolbox.

Table 7.4: Best Fitted SARIMA models

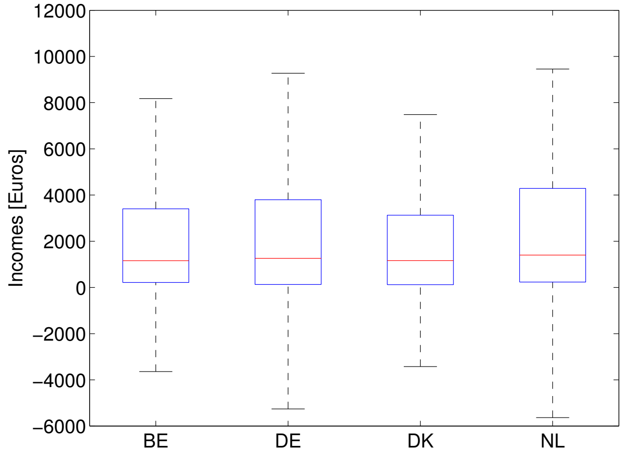
Country	Variable	Model	MAE 24 hrs	MAE 1 hrs
Belgium	λ^{DA}	$ARIMA\,(2,0,1)\,(1,0,1)_{24}\,(1,0,1)_{168}$	6.01	3.73
Belgium 2012	λ^{+}	$ARIMA\,(1,1,1)\,(1,0,1)_{24}$	26.89	18.87
Belgium 2012	λ^{-}	$ARIMA\,(1,1,1)\,(1,0,1)_{24}$	26.08	18.47
Denmark	λ^{DA}	$ARIMA\,(3,0,1)\,(1,0,1)_{24}\,(1,0,1)_{168}$	7.07	3.20
Denmark	λ^{+}	$ARIMAX\,(2,0,1)\,(1,0,1)_{24}\,(1,0,0)_{168}$	9.41	3.05
Denmark	λ^{-}	$ARIMAX\,(4,0,1)\,(1,0,1)_{24}\,(1,0,1)_{168}$	11.26	4.05
Denmark	$\lambda^{+/-}$	$ARIMAX\,(4,0,1)\,(1,0,1)_{24}\,(1,0,1)_{168}$	12.53	5.93
Germany	λ^{DA}	$ARIMA\,(1,0,1)\,(1,0,1)_{24}\,(1,0,1)_{168}$	8.36	3.98
Germany	λ^{I}	$ARIMA\,(2,0,1)\,(1,0,1)_{24}\,(1,0,1)_{168}$	7.87	3.34
Germany	$\lambda^{+/-}$	$ARIMA\,(3,0,1)\,(1,0,1)_{24}$	37.67	28.19
Germany*	$\lambda^{+/-}$	$ARIMAX\,(2,0,1)\,(1,0,1)_{24}\,(1,0,0)_{168}$	46.05	32.14
Netherlands	λ^{DA}	$ARIMA\,(2,0,1)\,(1,0,1)_{24}\,(1,0,1)_{168}$	4.95	3.39
Netherlands	λ^{+}	$ARIMA\,(2,1,1)\,(1,0,1)_{24}$	31.35	25.82
Netherlands	λ^{-}	$ARIMA\,(2,1,1)\,(1,0,1)_{24}$	34.11	28.24

*Computed imbalance prices, for further description see Section (7.3.1.3).

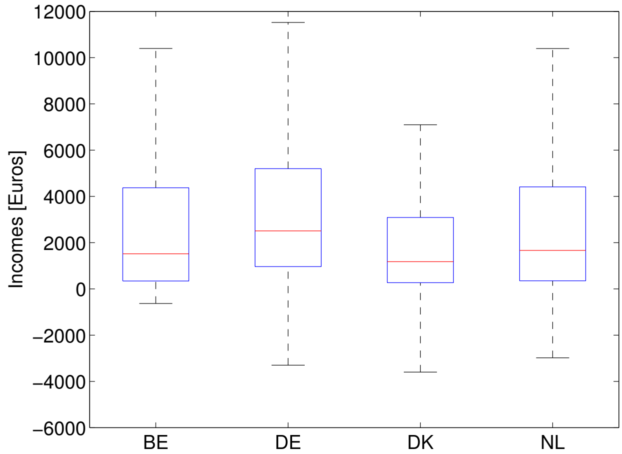
7.4 Results and Discussion

Figure 7.4.1 shows the hourly average income comparison between model results in contrast with bidding the expected energy in the different countries for December 2012. The model figures are the result of the whole optimization problem at three different stages (except for the German case that considers the DA and ID stages and deliver all possible generation). When considering the expected energy, ID bids are limited to 10% of the installed capacity to make results comparable.

The income from bidding the expected energy in each country is shown in Figure 7.4.1a. Except for Belgium and Germany, the mean differences between the countries are statistically significant (using the ANOVA test). The Netherlands presents the highest income, mainly driven by higher DA prices and net gains with the imbalanced positions. In the German case, the imbalance subsidy represents a significant percentage of the final income, of around 16%. Gawel and Purkus [61] signal that this subsidy represents windfall profits for wind generators. The Belgian income is similar as in Germany, but the absence of an imbalance subsidy is compensated with higher DA and IM prices. Finally, the Danish case presents the lowest income; in the Danish case the effect of the imbalance subsidy is 7% of final income. The Danish DA prices are the lowest among the analyzed countries, and additionally, due to dual imbalance pricing, there is a net cost from imbalanced positions.



(a) Results from bidding the expected energy



(b) Model results

Figure 7.4.1: Hourly average income

Figure 7.4.1b shows the result from the three-stage optimization model. In all the cases, the model results outperform in comparison with bidding the expected energy in the markets and the differences between both are statistically significant at 95% level. The income resulted from the model increases considerably in the German case, which represents an average increase of 59%. The liquid German ID market allows the trading of updated energy forecast, which is more limited in the other countries due to lower liquidity.

For the Dutch case, the average income increases by 18% with the model results. While in the Danish case, the income increases by 10%. In the Belgian case, the income increases 26%, considering the tolerance margins. However, without these margins the average income increases 15% more than with these margins. This result is astounding because tolerance margins could represent a penalization for offshore wind farms, instead of an economic compensation for possible higher imbalance costs. The Belgium Regulator has considered the removal of these margins [161], but they are still in place.

In all the considered countries, negative prices for long positions occurred in December 2012. In Denmark, Belgium and the Netherlands, as IM prices are quite certain close to real time, it is possible to reduce wind generation to reduce losses from long positions and help to restore the system balance. This is much less certain in the German case due to the monthly publication of IM prices.

Table 7.5 shows the income from the model results by the different markets as a percentage of total income. As expected, the higher income comes from the DA market, with similar percentages between countries. This percentage is lower in Belgium, which is compensated with higher income from energy imbalances.

The percentage of the ID income is low in the different countries as the income from sales is cancelled out with purchases costs. In the Danish case, in December 2012, IM prices were higher for short positions than for long positions; therefore, the best strategy consists in selling less than the expected energy in the DA market and selling part of the updated energy forecast in the ID market. This leads to positive income in the ID market.

Table 7.5: Income from model results by markets

Country	DA	ID	Long positions	Short positions	Imbalance subsidy
Belgium	52.61%	-0.58%	39.46%	8.51%	2
Germany	62.3%	1.75%	18.45%	1.43%	16.07%
Denmark	65.77%	8.81%	27.76%	-8.95%	6.61%
Netherlands	65.83%	-0.50%	40.37%	-5.70%	-

In all the four countries analyzed, negative IM prices occurred during December 2012. However, they were more often in Belgium and Germany. For this reason, imbalance cost for short positions was positive in Germany and Belgium, with higher values in the latter.

The model considers the price forecast to compute the optimal bids in the DA and ID markets. Therefore, the market bids and final energy delivered may differ from the expected energy. Additional energy imbalances can have negative consequences for the system. The energy imbalances (in absolute terms) from the model results of each country and the energy imbalances resulted from bidding the expected energy in the different markets are shown in Figure 7.4.2. The energy imbalances from bidding the expected energy in the markets are around 26% of final generation, while in the Belgian case with tolerance margins, the final energy imbalances increase to 61% of the final generation, imbalances slightly decrease with the tolerance margins in comparison without applying them. The rest of the cases present similar imbalances, with slightly lower imbalances in the Dutch case.

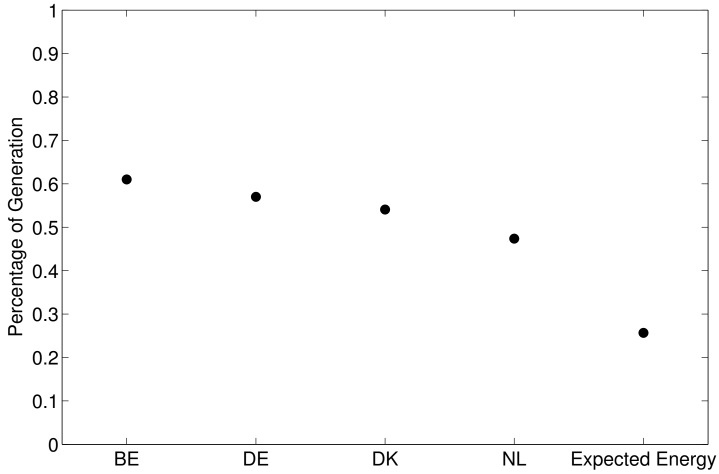
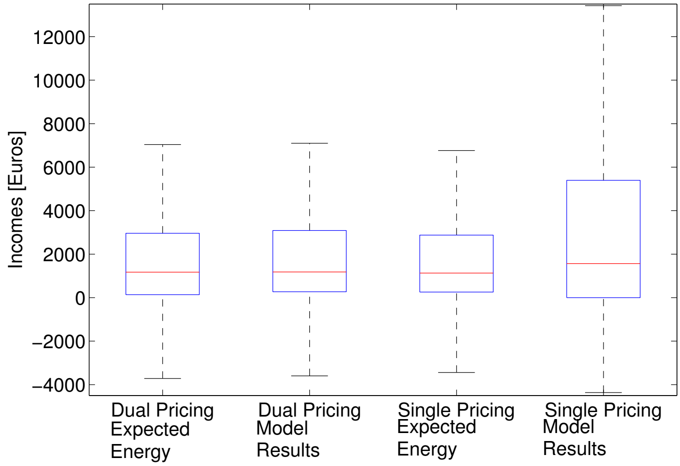


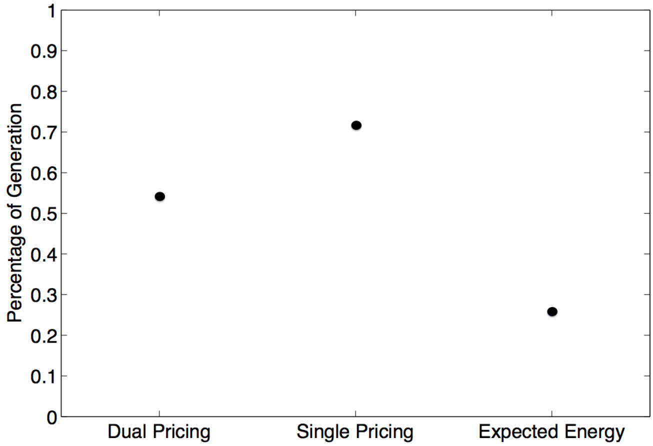
Figure 7.4.2: Mean absolute energy imbalances from the model results

Denmark: dual versus single imbalance pricing

In the Danish case, it is possible to compare the effect of applying single pricing for wind farms, as it is done for consumption units. Figure 7.4.3 shows model results from this comparison. As expected, the single pricing can give higher income, but also depends on whether market parties bid the expected energy or whether energy bids also consider prices uncertainties (Figure 7.4.3a). As shown in the countries comparison (Figure 7.4.2), if the wind farm maximizes its income, the single pricing leads to higher imbalances than the dual pricing, but in both cases, they are higher than bidding the expected energy in the markets (Figure 7.4.3b).



(a) Income applying different imbalance pricing



(b) Mean absolute energy imbalances from dual and single pricing

Figure 7.4.3: Dual versus single pricing in Denmark

Germany: impact of energy imbalances on imbalance prices

One of the assumptions of the model is that the offshore wind farm is small and does not affect the market prices. To verify this assumption, the effect of energy imbalances on the IM prices is investigated, by using real data of reserves bids and activated reserves from Germany. The additional imbalances from the model results are assumed to increase the need of RR. The non-transferable costs are not considered in this computation as explained in Section 7.3.1.3, but the same methodology is used to compute the effect of additional imbalances. With the new IM prices resulting from the increase of activated reserves, the income of the wind farm participating in the German market decreases by around 3%, which is relatively small in comparison with possible gains of the model. This effect can be higher for the rest of the countries where IM prices are based on the marginal energy reserve costs, in contrast with the German case, which applies the average reserve cost for IM prices.

In all analyzed countries, balancing rules have different impacts on the final revenues of the wind farm. Therefore, the impact of balancing rules should be considered in the design of other market rules, such as the support schemes for RES-E, especially intermittent RES-E, as they have larger imbalances.

7.5 Conclusions

This chapter compares the economic impact (and market signals) of different balancing rules applied in four European countries (Belgium, Denmark, Germany and Netherlands). By using a stochastic optimization model, which incorporates relevant uncertainties that affect the participation of wind power producers in electricity markets. The model results outperformed from those obtained by bidding the expected energy in the markets, which validates the usefulness of the model. The model shows that balancing rules have a significant impact on the profits of wind power producers, on bidding strategies and on final energy imbalances. Furthermore, these short-term balancing rules can have an impact on system operational costs and even on investment signals.

The model results show that wind power producers, in order to maximize their revenues in the short-term markets can arbitrate between different market prices. The bids on these markets will not necessarily correspond to the expected energy, but they also depend on the price forecasting and on the rules related to the allocation of balance responsibility and imbalance prices. In addition, the application of single or dual pricing does not ensure that wind power producers bid the expected energy, as generators would hedge against the expected imbalance prices.

The single pricing gives a higher income to wind farms, but also leads to higher energy imbalances. In addition, even within the single pricing design, there are different design options to compute imbalance prices, for example those prices can be based on the marginal balancing energy costs (Belgium and the Netherlands) or based on the average costs (Germany). Single pricing based on the marginal cost of reserves gives the marginal price signal of system cost of additional imbalances, which is a stronger incentive to avoid energy imbalances in the same direction of the system than the imbalance prices based on average reserve cost.

The allocation of balance responsibility to wind power producers should be considered in interaction with the imbalance pricing design. In the German case, the single pricing based on the average energy cost of reserves can increase the energy imbalances, which can have a negative impact on the system balancing costs.

As discussed earlier, balancing regulations are interrelated (i.e., the allocation of balancing responsibility and imbalance pricing) and should be considered together. The quantitative analysis shows that in the Belgian case, tolerance margin can represent a penalization instead of a potential benefit for wind power producers. This is due to the change of the Belgian imbalance pricing from dual pricing to single pricing, without changes in tolerance margins for offshore wind.

The publication of system imbalance and imbalance prices close to real time is an important element to reduce system imbalances in case of generation surplus and existence of negative imbalance prices. In Germany, imbalance prices are published with a month delay. It does not allow market parties to react to negative imbalance prices accurately. This reaction is possible in the Netherlands and Belgium, as these countries publish the system imbalance and imbalance prices every minute and two minutes, respectively. In Denmark, this publication is done within an hour.

With respect to the imbalance subsidies (applied in Denmark and Germany), they effectively increase the feed-in premium as they are given per megawatt hour delivered. These subsidies limit the reaction of wind power producers to negative prices by the amount of the subsidy. In the German case, this subsidy represented a significant part of the estimated income for the year 2012, which might have resulted in windfall profits.

To conclude, best practices can be highlighted from the presented analysis. First, the publication of imbalance prices close to real-time encourages the reduction of energy imbalance and gives incentives to support the system balancing. Second, single imbalance pricing based on the marginal costs of reserves can represent a good design that encourages renewable sources to balance themselves, but also gives the possibility for flexible units to deviate from energy imbalance to support the system. In case of network congestions, a mix of single and dual pricing may prevent adverse price signals, as described in Chapter 5. Third, distortions in the allocation of balance responsibility, such as tolerance margins, should be avoided. Finally, the allocation of balance responsibility by itself, is not automatically translated in lower costs if market distortions exist. From discussed perspectives, the Netherlands presents a more robust design of balancing rules in relation to intermittent RES-E.

The System Operators should be aware of the economic incentives that intermittent RES-E have and incorporate those incentives in the operation of the system. Furthermore, the design of balancing rules should be considered in the design of the support schemes, as they can significantly impact the revenues of renewable sources, especially intermittent RES-E, such as wind and solar power.

Chapter 8

Effects of lack of harmonization of European balancing rules

The author would like to thank Reinier van der Veen for his comments on this chapter and Malte Rödl for his contribution in the agent based modeling.

8.1 Introduction

In Europe, one of the goals of electricity policy is to achieve an Internal Electricity Market (IEM), specifically defined by the European Commission [12]. Because of this, the integration of the different markets is taking place within Europe. In the short-term markets, the harmonization of day-ahead and intraday markets is expected to be achieved by 2014 [6], whereas for balancing mechanisms there is not a specified time for full harmonization. The Agency for the Cooperation of Energy Regulators (ACER) and the European Network of Transmission System Operators for Electricity (ENTSO-E) are working on the development of Framework Guidelines and Network Code on Electricity Balancing [5, 4]. The Code intends to set general principles for the member states for the procurement, activation and settlement of balancing services. However, although the Code would contribute significantly to harmonize different aspects of the balancing mechanisms, in some other aspects, it is very general and gives freedom in the design of balancing rules to each country. This freedom may lead to the preservation of the current differences between countries.

The balancing mechanisms include different institutional design options, which play an important role in achieving economic efficiency of these mechanisms [10]. For example, different institutional designs can be applied for the procurement of balancing services, mechanisms for allocation of balancing costs to market parties, and incentives for market parties to decrease energy deviations, among others. As a consequence of these differences in balancing mechanisms, prices of balancing services and imbalance prices may not reflect balancing costs in the same way in the different countries.

In the context of different balancing designs, cross-border interchange of balancing services and short-term electricity trade through intraday markets do not necessarily improve economic efficiency. Furthermore, the lack of harmonization of balancing mechanisms could increase balancing costs and endanger the national system balance in certain countries.

This chapter describes relevant aspects of short-term market designs of some North European countries: Belgium, Denmark, France, Germany, Great Britain and the Netherlands. These countries are interconnected and they are increasingly harmonizing the day-ahead and intraday markets. There is even an exchange of balancing services between them through the implementation of International Grid Control Cooperation (IGCC) [170][1]. In addition, these countries surround the North Sea where offshore wind developments are expected to take place in the coming years and decades. Therefore, the organization of short-term market designs in these countries becomes more important to efficiently manage wind generation uncertainties.

Furthermore, this chapter describes the advantages and disadvantages of short-term cross-border electricity trade between these North European countries. Then it describes the main causes for losses of economic efficiency from short-term cross-border electricity trade and to what extent those aspects are included in the Network Code on Electricity Balancing proposed by ENTSO-E [4]. Finally, this chapter illustrates the effect of different imbalance pricing schemes in neighboring countries by using an agent-based model. The results from the model measure the possibilities of multinational companies to arbitrate between markets and the effect on the revenues for system operators.

8.2 Short-term cross-border electricity trade

European markets have differences in prices for balancing services, balancing costs and imbalance prices. Some of these differences can be considered "structural", those that depend on the generation mix, transmission capacity, market structure and different levels of flexibility in the system. On the other hand, there are some differences that are "nonstructural", which mainly depend on market designs and market rules applied in different countries.

In the presence of only "structural" differences, short-term cross-border electricity trade (this includes cross-border electricity trade through intraday markets and through the exchange of balancing services) can potentially improve economic efficiency. This short-term cross-border electricity trade can happen in different ways depending on the actors involved and the mechanisms used. Market parties can sell balancing services to SOs (national or neighboring) or they can have portfolio strategies to balance themselves within the country and even between countries. In addition, SOs can trade balancing services between them without the direct involvement of market parties. The cross-border exchange of balancing services depends on cross-border balancing 'models' that are in place [10].

In the presence of "nonstructural" differences, gains in economic efficiency from short-term cross-border electricity trade cannot be guaranteed.

[1]In addition to IGCC, German and Swiss market parties can bid in the French balancing market. Additionally, the interchange of balancing services occurs between French and British SOs [171].

8.2.1 Benefits from short-term cross-border electricity trade

Cross-border short-term electricity trade may lead to a better use of balancing sources between countries. But this trade can take place in different ways as van der Veen [10] comprehensively explained. This section describes some of the economic benefits of cross-border exchange and the ways this can happen, assuming that prices difference between countries are only due to "structural" differences.

8.2.1.1 Intraday cross-border electricity trade

After the day-ahead market, cross-border wholesale trade is possible through intraday markets (or intraday bilateral contracts in case they are allowed). In order to reduce imbalance costs, market parties can arbitrate between markets by changing imbalanced positions close to real time by means of cross-border intraday trade.

A company that has generation in neighboring countries may trade cross-border to reduce imbalance costs of a company that has generation in neighboring countries and reacts to imbalance prices, but by doing this, the system imbalance in one or more countries can be negatively affected. However, this may not be always the case as energy trade in intraday markets can be in the same or opposite direction of the system, as shown in Table 8.1.

Table 8.1: Impact of intraday cross-border electricity trade to decrease imbalance costs

(a) Market parties from country A exports to country B

		Country A imbalance	
		Positive	Negative
Country B imbalance	Positive	+-	- -
	Negative	++	-+

(b) Market parties from country A import from country B

		Country A imbalance	
		Positive	Negative
Country A imbalance	Positive	- +	+ +
	Negative	- -	+ -

++ positive impact on system imbalances for both countries
-+ negative impact on system imbalances for Country A and positive impact on system imbalances for Country B
+- positive impact on system imbalances for Country A and negative impact on system imbalances for Country B

- - negative impact on system imbalances for both countries

Those market parties that have a big generation portfolio and are also active in neighboring countries have more flexibility to arbitrate between markets, particularly in the case of low liquidity in the intraday markets. A market party in one country can set a bid in the intraday market that can be matched by a bid from the same company based on the neighboring country. This is the case of continuous intraday markets which are in place in most European countries as explained in Chapter 2.

European intraday markets The European intraday markets have been developed after the day-ahead markets. However, intraday markets become more relevant due to the increase of intermittent RES-E, such as wind and solar power. In Europe, there are 14 countries without intraday markets and 15 with them [40]. Table 8.2 shows the Gate Closure Time (GCT)[2] and trading volumes in 2012 for some relevant European intraday markets. The intraday market trading volumes remain low in most countries, except for the Iberian market. Different European institutions foster liquidity in the intraday markets and the shift of the GCT closer to real time [38].

Table 8.2: Market designs and trading volume in the European intraday markets

Market area	Market Operator	Intraday Gate Closure Time	2012 (TWh)	
			DA market	Intraday market
Belgium	Belpex	5 minutes	16.5	0.51
France	EPEXSPOT	45 minutes	59.3	2.2
Germany/Austria	EPEXSPOT	45 minutes	245.3	15.8
Netherlands	APX-ENDEXAPX	5 minutes	49.5	0.45
Nordic Region*	Nord Pool	60 / 120 minutes (Norway)	334.0 **	3.2 **
Spain and Portugal	OMIE	3:15-6:15 horas	227.9	52.1
UK	N2EX	15 minutes	94.8	38 *
UK	APX UK	30 minutes	4.8	13.7*

*Prompt and Spot market.

**Including Estonia and cross-border electricity trade with Germany.

European cross-border intraday trade Figure 8.2.1 shows the current allocation methods of cross-border intraday transmission capacity within European countries. The overall objective in Europe is the implementation of the intraday target model by the end of 2014, which is quite challenging due to differences in the market designs. ACER [14] and ENTSO-E [6] support the pan-European intraday target model of continuous implicit trading, with a reliable pricing of cross-border transmission capacity that reflects congestions and the allocation of congestion rents. Further description of European intraday market integration can be found in Chapter 2.

The future implementation of a single European intraday market will allow cross-border energy trade closer to real time. The efficiency gains from this trade will depend, among other issues, on the existing balancing mechanisms of the different countries. This single intraday market requires a single GCT. In the analyzed countries, the shortest GCT is applied in Belgium and the Netherlands, which corresponds to 5 minutes.

[2]This refers to the last time when bids can be submitted.

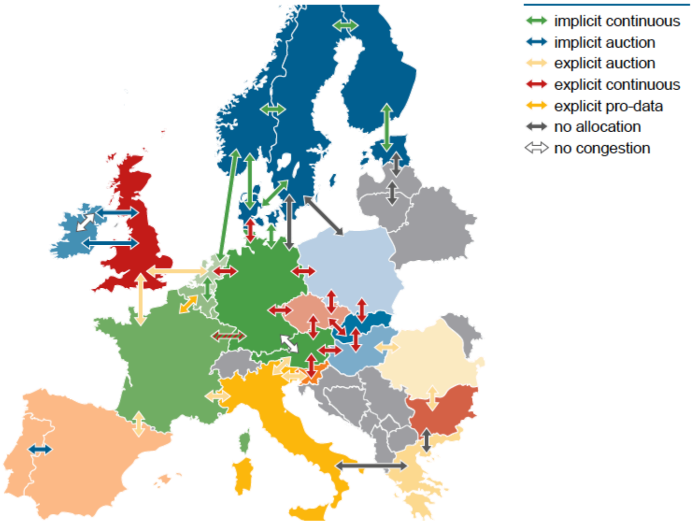


Figure 8.2.1: Intraday transmission capacity allocation [3]

8.2.1.2 Imbalances netting between countries

As discussed earlier, imbalances between countries can differ for different reasons, for example, due to varying forecast errors of demand and intermittent RES-E, or generation outages. Therefore, by trading the surpluses or deficits of energy close to real-time between countries, the required balancing energy can be reduced as shown in Figure 8.2.2. The system surplus of country A can compensate the system shortage of country B. By doing this, the net imbalance is reduced in both countries and consequently the balancing costs as well. Country A reduces the activation of upward regulation, while country B reduces the activation of downward regulation. The amount of energy transferred is restricted by the available transmission capacity between the countries. This netting of imbalances is performed by the TSOs. This mechanism has been implemented already in some North European countries (Belgium, Denmark, Germany, the Netherlands, Czech Republic and Switzerland) through the International Grid Control Cooperation [170]. The international netting started with the German and Danish trial in October 2011. The price settlement for imbalance netting is based on the opportunity cost (avoided costs from the activation balancing energy), further description can be found in TenneT [172].

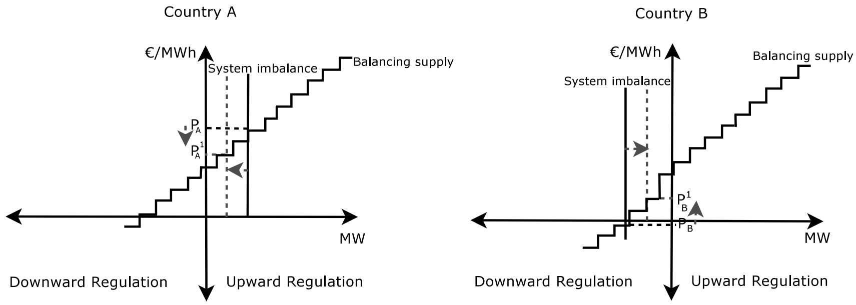
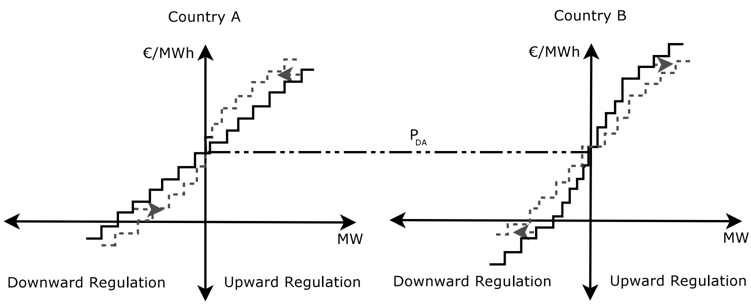


Figure 8.2.2: Imbalance netting between countries

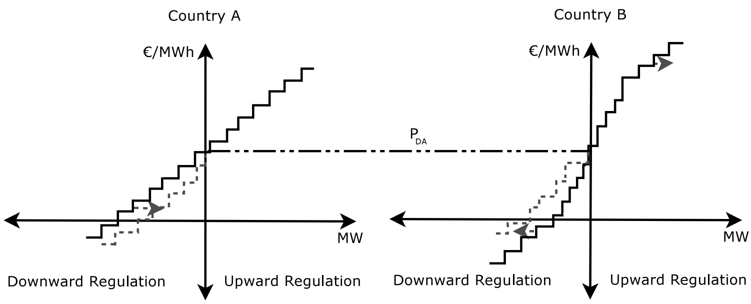
8.2.1.3 Cross-border exchange of balancing services

Cross-border balancing markets allow using balancing services more efficiently. The effect of cross-border exchange of balancing services is represented in Figure 8.2.3, where country A has cheaper balancing sources in comparison to country B. As a result of a common merit order list, the balancing energy bid ladders tend to be equal between countries in case there is enough interconnection capacity available. In Figure 8.2.3a, it is assumed that day-ahead prices coincide, and there is sufficient available transmission capacity between countries; whereas in Figure 8.2.3b the day-ahead price is higher in country A than in country B. In Figure 8.2.3b, if there is a need for upward regulation in country B, this cannot be supplied by country A, as transmission capacity is fully used. In this case, downward regulation can be exported at cheaper costs than national activation from country A to country B.

Reservation of transmission capacity for balancing purposes has been an issue debated for long time. Although in theory, from a social welfare perspective, there exists an optimal level of reservation of transmission capacity for balancing purposes, such reservation will reduce trading possibilities in the day-ahead and intraday markets [173]. ACER [5] argues that this reservation should be allowed only when it can be proved that it to increases social welfare.



(a) Without congestions between countries



(b) With congestions between countries

Figure 8.2.3: Effect of cross-border balancing markets

8.2.2 Inefficiencies of short-term electricity trade due to differences in balancing rules

This subsection describes the possible negative effects of short-term electricity trade, especially as a result of market distortions and lack of harmonization of balancing rules between countries. Differences in market rules between countries ("nonstructural" differences) may imply that balancing costs are not reflected in the same way, and they are translated into different prices for balancing services and imbalances. Subsequently, the short-term cross-border electricity trade may negatively affect economic efficiency, the cost faced by national consumers and cross-border subsidizing between countries. Furthermore, these price differences affect investment signals in flexibility, because of "nonstructural" differences.

Chapter 4 provides an updated description of relevant differences in the procurement of balancing services between some European countries. This section describes some of the relevant aspects that can lead to different prices for balancing services, and therefore impact imbalance prices. This section does not intend to be exhaustive, but it gives a general overview of relevant design variables for balancing mechanisms and possible effects on prices for balancing services. The main focus of this section is on procurement designs of FRR.

ENTSO-E [174] argues that the Network Code of electricity balancing should aim to increase liquidity, avoid perverse incentives and increase social welfare. But ENTSO-E leaves the choice open whether or not to harmonize design variables of balancing mechanisms, which can create perverse incentives and decrease social welfare.

Vandezande et al. [175] show through statistical analysis that static strategies between France and Belgium in 2008 can be profitable because of the imbalance pricing schemes applied in these countries. However, Vandezande et al. [175] use a static analysis with a single strategy for the whole year, while strategies can change from hour to hour. Besides differences in imbalance prices, there are other relevant variables that can negatively impact economic efficiency effects from cross-border electricity trade, as explained below.

ENTSO-E [174] will launch a pilot project to test the feasibility of the BritNed interconnector for balancing, as the Netherlands and Great Britain have fundamental differences in the way they organize balancing markets. This analysis should be extended to the European context to analyze to what extent differences in short-term market designs lead cross-border electricity trade and, at the same time, impact the overall economic efficiency in the countries.

8.2.2.1 Procurement time of balancing services

SOs purchase balancing capacity to ensure the availability of energy balancing services in real time. These services are bought in organized markets or through bilateral contracts. The selected bids receive an availability payment to compensate market parties for committing production capacity. When there is a separate market for balancing capacity and balancing energy, BSPs with contracted balancing capacity are usually obliged to bid into the balancing energy market.

Table 8.3 shows the procurement time of FRR in different North European countries. The longer the procurement time of FRR, the higher the costs could be. This is because uncertainties decrease closer to real time and, therefore, the reserve requirements decrease as well. As availability costs are not usually reflected in the imbalance prices, differences in the procurement of FRR energy services give different energy costs. These costs are translated into imbalance prices.

Table 8.3: Timing of the balancing markets and imbalance settlement

Country	FRR GCT (capacity)	FRR GCT (energy)	STU	Imbalance prices' disclosure
Belgium	Day-ahead	Day-ahead	15 minutes	Every Minute
Denmark (West)	Month-ahead	Hour-ahead	1 hour	Hourly
France	Day-ahead	Hour-ahead	30 minutes	30 minutes
Germany	Week-ahead	Week-ahead	15 minutes	Next calendar month
Netherlands	Year-ahead	Hour-ahead	15 minutes	Every Minute
Great Britain	Yearly until day-ahead	Yearly until day-ahead	1 hour	Hourly

*Information checked in November 18, 2013.

Besides the time period of balancing capacity procurement, a relevant aspect is to determine to what extent new bidders that have not been selected in the balancing capacity market can bid in the balancing energy market. This is possible for FRR in France and the

Netherlands, and it provides short-term flexibility. In the Netherlands, the GCT for energy balancing services for FRR and RR is the day before at 14h45. If bids are not activated by TenneT, they can change until one hour before execution [103]. In France, FRR bids must be submitted the day before at 16h00 and they can be modified until one hour before operation [176]. In Denmark-West, FRR are bought monthly and at a fixed price [177], RR bids must be submitted before 17h00 of the day before, and bid prices and quantities can be adjusted 45 minutes before the delivery hour [97]. In Germany, FRR are bought in a weekly market, for both capacity and energy balancing services. In Great Britain, there are different balancing services that have the function of FRR and RR, which are bought from year-ahead to the day-ahead [178]. In Belgium, both year-ahead and month-ahead procurement of FRR take place [179].

In Germany, the availability payments represent two thirds of the reserves costs (availability plus energy) [119]. It is difficult to conclude from the comparison with other countries that availability costs are only higher because of the longer purchase time, as other factors also have an important impact on balancing costs, such as the generation mix and interconnection capacity with neighboring countries, among others. Additionally, in most of the countries under study, the cost of balancing capacity is not published, which limits the value of the analysis.

Figure 8.2.4 shows the expected effect of high availability payments from a longer procurement time of reserves in country A, which can be translated into lower balancing energy prices. This is because part of the energy costs can be recovered with availability payments. As country A has lower balancing energy prices, with cross-border interchange of reserves, country A may export balancing services to country B. However, if availability payments were lower (because of a shorter procurement time), there would not have been reserve interchange between both countries.

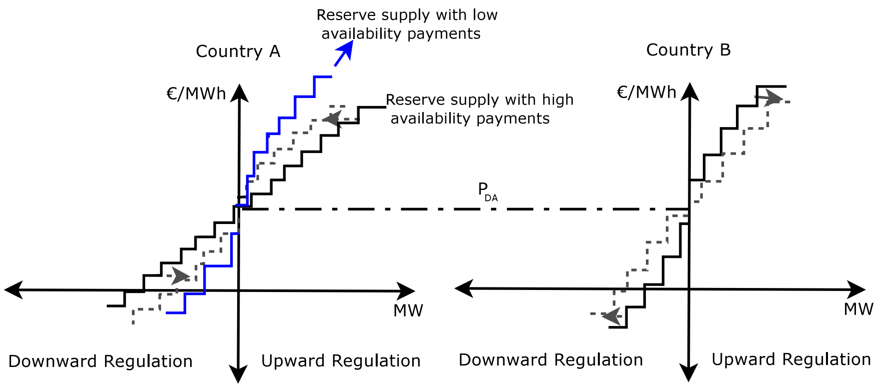


Figure 8.2.4: Expected effects of availability payments

8.2.2.2 Balancing timing

The Settlement Time Unit (STU) refers to the interval over which imbalances are computed. A short STU gives incentives to intermittent RES-E to compute energy forecasts over small time intervals. The resulting energy schedules give SOs more accurate information about future energy delivered, which can decrease system balancing needs and costs associated. The STU is 15 minutes in Belgium, Germany and the Netherlands, 30 minutes in Great Britain and France, and one hour in Denmark.

Another important timing variable is the publication of imbalance prices. Imbalance prices reflect the costs of energy imbalances. The publication of these prices close to real time permits market parties to reduce energy imbalances by short-term trade. These trades can help to reduce the system imbalance. The Netherlands and Belgium publish imbalance prices every minute and two minutes, respectively. Germany publishes imbalance prices the next calendar month, which prevents market parties from reacting to imbalance prices on short notice. Those countries that publish imbalance prices closer to real time can benefit from energy adjustments that favor the system balancing, in contrast to those countries like Germany where higher uncertainties of imbalance pricing may lead to larger energy imbalances.

8.2.2.3 Inclusion of internal congestion costs in the imbalance prices

In the computation of imbalance prices, the balancing costs related to internal network congestions can be fully, partially or not incorporated. For instance, in Great Britain, the increase of balancing costs due to internal congestions is not reflected in imbalance prices, as these are removed following a flagging procedure [178]. From all the actions taken by the TSO, 27% of them were used to solve system constraints [109]. In other European countries this procedure does not exist and imbalance prices also include the costs of internal congestions. ACER [5] and ENTSO-E [6] argue that imbalance prices shall not include congestion costs. The procedure used to release internal congestions should eventually be the same for all countries to avoid distortions.

The exchange of balancing services and energy as a response to market prices will not ensure economic efficiencies if imbalance prices reflect costs of internal congestions in different ways. Those imbalance prices that incorporate internal network costs will be higher, *ceteris paribus*, than those countries that do not incorporate them. The effect of including internal network congestions costs in imbalance prices can have a similar effect as the one illustrated in Figure 8.2.4.

Renewable energy sources, such as offshore wind farms (located far from consumption areas), can increase internal network congestions. In addition, changes in the generation mix due to the phase out of nuclear power plants, as in Germany, have increased internal congestions considerably [125]. Therefore, locational price signals become more relevant in countries like Germany [116].

8.2.2.4 Pricing mechanisms

As earlier described, balancing services' payments are usually divided in two main components: balancing capacity and balancing energy. The cost of balancing energy is allocated to those market parties that have energy imbalances. SOs use different payment rules for balancing energy as shown in Table 8.4. In the Netherlands, when marginal pricing is applied, all the activated balancing energy bids for upward regulation receive the marginal price of upward regulation and those for downward regulation receive the marginal price of downward regulation [103]. In Western Denmark, FRR are remunerated in proportion to the day-ahead price. RR are bought from the Nordic balancing market and priced at the marginal price when there are not network congestions, otherwise the pay-as-bid rule is used [180]. Belgium, France and Germany use the pay-as-bid pricing rule, which means that balancing energy is remunerated with the bid price [179, 176, 181]. In Great Britain, there are different balancing services that have the function of FRR. They are bought through bilateral contracts and tenders, in which both availability and utilization prices are determined [182].

Table 8.4 shows the imbalance pricing mechanism used in the analyzed countries. Generally, two main approaches of imbalance pricing exist: single and dual pricing (see Appendix D for further description of these pricing methods). Germany, the Netherlands, Belgium (since January 2012) and shortly Great Britain [104] mainly apply a single pricing mechanism. These countries also apply an incentive component in case of high system imbalances. Under single pricing, imbalance prices are computed based on the marginal balancing energy or on the average costs of activated balancing energy bids. In the Netherlands and Belgium, imbalance prices are based on the marginal energy bid activated, whereas in Germany, they are based on the average costs of the activated balancing energy bids.

Table 8.4: Pricing of balancing energy and imbalance pricing

Country	Pricing of balancing energy	Imbalance pricing mechanism	Imbalance Price
Belgium	Pay-as-bid	Single pricing	Marginal price
Denmark	Marginal Price/Pay-as-bid*	Dual pricing	Marginal price
France	Pay-as-bid	Dual pricing	Average price
Germany	Pay-as-bid	Single pricing	Average price
Great Britain	Hybrid	Dual pricing	Average price
Netherlands	Marginal price	Single pricing	Marginal price

The dual pricing mechanism is applied in the Nordic Region (for generation units), France, and Great Britain (currently). Great Britain is moving towards marginal single pricing including demand disconnection costs [2014].

Resulting from the imbalance pricing rules, imbalance prices may significantly differ between countries. As shown in Table 8.5, the differences between imbalance prices for short and long positions substantially differ in some of the European countries. The countries that apply dual pricing penalize imbalances stronger than those with single pricing (France, Great Britain and the Nordic Region). Therefore, in those countries with dual pricing, strategies to avoid imbalances based on cross-border electricity trade can take place. However, this can increase the costs for those countries with single pricing.

Table 8.5: Mean day-ahead and imbalance prices for different European countries

Country	2010 Prices (€/MWh)			2011 (€/MWh)			2012 (€/MWh)		
	Day-ahead	Short	Long	Day-ahead	Short	Long	Day-ahead	Short	Long
Belgium	46.30	60.58	29.02	49.37	62.73	29.22	45.85	4.05	51.84
Denmark (DK1)	46,49	50.88	40.82	58,87	64.36	51.44	43,12	47,90	38.26
France	47.50	63.08	39.65	48.89	60.37	39.59	46.94	54.68	37.73
Germany	44.48	43,96	43,96	51.18	32.96	32.96	42.27	46.48	46.48
Great Britain**	-	48.84	35.80	47.18**	53.11	41.49	44.51	53.01	38.93
Netherlands	45.37	45.54	43.37	52.07	53.85	45.80	48.05	54.10	46.58

*Great Britain day-ahead prices correspond to APX UK.

**From April 2011 to December 2011.

8.3 EU short-term market designs under high penetration of intermittent RES-E

European harmonization of balancing mechanisms is not a prerequisite for the exchange of balancing services or short-term trade. However, as discussed earlier, the lack of harmonization can give losses in economic efficiency. The choice of a single design with a harmonized set of rules can be a difficult task because of the diversity of mechanisms currently in place. Furthermore, for some countries, these differences in balancing mechanisms might cause a net export of flexibility to neighboring countries which does not come at the benefit of a global increase in economic efficiency.

General principles and current practices can be considered when designing minimum requirements for a common market design. Table 8.6 shows the current best practices in the design of balancing mechanisms in contrast with those designs proposed by ENTSO-E [6, 4] and ACER [5].

As discussed earlier, the intraday market represents the last option for BRPs balancing without the involvement of the SO. The latest GCT is 5 minutes before real time, applied in the Belgian and Dutch markets, which may also be suitable for other markets.

The design of the procurement method for balancing capacity has important implications in terms of economic efficiency and security of the system. In the context of high intermittency and variability of energy sources, long procurement time of balancing capacity may lead to overcontracting or undercontracting. In case of overcontracting, some capacity is unnecessarily unavailable for trading in the day-ahead and intraday markets. However, if balancing capacity is contracted after the day-ahead market, uncertainties about intermittent generation are reduced and balancing requirements are more accurate. Belgium and France have a shorter procurement time (day-ahead) of balancing capacity for FRR[3]. Furthermore, the acceptance and modification of balancing energy bids closer to real time allows balancing service providers to incorporate new available information in their bids. In Denmark and the Netherlands this is one hour before real time, according to ACER [5]

[3]Notice that ENTSO-E [4] allows a contracting period of more than one year, which is subject to regulatory approval.

recommendation.

With respect to STU, in three of the countries (Belgium, Germany and the Netherlands) it is 15 minutes, which provides an incentive for short-term forecasting of intermittent RES-E and eventually reduces energy imbalances.

With respect to the pricing mechanism, ENTSO-E [4] recommends the use of marginal pricing for balancing energy, which is currently applied only in the Netherlands. For imbalance pricing, ENTSO-E [4] recommends at least average pricing of activated balancing energy bids. However, if the marginal pricing rule is applied for balancing energy, this can also be applied for imbalance prices. Otherwise, there is a gain for the TSO when using a pay-as-bid method for balancing energy and marginal pricing for imbalances (as currently applied in Belgium). Furthermore, the imbalance pricing mechanism ideally needs to be harmonized for all countries. A single pricing mechanism has different advantages [118, 21]; however, in case of network congestions this pricing mechanism can present some disadvantages [116].

An important aspect for balancing designs is transparency in all the different mechanisms and in the publication of market data. Currently, all the analyzed European countries, except for Germany, do not publish the availability payments for FRR. In addition, timely publication of imbalance prices can discourage imbalances that affect the system. ENTSO-E [4] highlights that national network codes should require the publication of volumes and prices of procured balancing energy in a time frame not longer than one hour. The Netherlands and Belgium make publicly available the marginal balancing energy price every minute and every two minutes, which provides real-time information to market parties to avoid imbalances.

Furthermore, electricity has time and location characteristics. The more these characteristics are incorporated in prices, the more efficient the system can be. Borggrefe and Neuhoff [9] evaluate different balancing mechanisms by six different criteria, i.e. criteria related to flexibility of the system, inclusion of demand side and effective market power monitoring. They conclude that nodal pricing is the more suitable design for balancing mechanisms which potentially improve efficiency in the integration of wind power in Europe. Although nodal pricing can be a suitable solution to harmonize current European designs, the implementation of nodal pricing in Europe requires a significant change of current market designs [116]. Alternative options, which require less significant changes in current designs, should also be explored in the meantime. For example, the alignment of different time frames of the markets, the selection of common pricing rules, publication of relevant data, and agreement on homogeneous market solutions to deal with network congestions.

Table 8.6: Countries' best practices and proposed designs by ENTSO-E [4], ACER [5], ENTSO-E [6]

Design variable	Best Practice	Proposed designs
Intraday market Gate Closure Time	5 minutes (NL, BE)	1 hour
FRR balancing capacity Gate Closure Time	Day-ahead (BE, FR)	Year-ahead*
FRR balancing energy Gate Closure Time	1 hour (DK, NL)	1 hour
Settlement Time Unit	15 minutes (BE, DE, NL)	30 minutes
Balancing energy pricing	Marginal (NL)	Marginal
Imbalance Pricing	Marginal (NL, BE)	At least average
Publication of balancing energy bids	1 hour (DE)	1 hour
Publication of activated balancing energy	Every minute (NL)	1 hour
Balance Responsibility for wind power	Full (NL)	Full

*The possibility of more than one year is open and subject to regulatory approval.

8.4 Simulation of arbitrage opportunities due to imbalance pricing differences

This section presents the description of an agent-based model used to simulate the effect of the lack of harmonization in imbalance pricing mechanisms in neighboring countries. Two main aspects of cross-border electricity trade are studied: the impact on companies' profits and SOs' revenues. The companies that are actively participating in neighboring countries can trade expected energy imbalances between countries in order to reduce their imbalance costs. The impact of System Operators' revenues represents the extra costs/revenues for them and a net transfer of balancing resources from one country to another. This net transfer represents higher costs for consumers without improvements in economic efficiency as discussed in Section 8.2.2.4.

8.4.1 Use of an agent-based model for electricity balancing

An agent-based is a modeling paradigm which focuses in individual decisions. Shalizi [183] defines an agent as a "persistent thing which has some state we find worth representing, and which interacts with other agents, mutually modifying each others' states". Therefore, the components of an agent-based model "are a collection of agents and their states, the rules governing the interactions of the agents, and the environment within which they live". In electricity markets, an agent-based model has significant applications because of the interactions of market parties and rules governing the technical and institutional characteristics of the market. Weidlich and Veit [184] provide a survey of the applications of an agent-based model in different domains in the electricity market. The applications vary from strategic bidding, and market power analysis, market dynamics, among others.

An agent-based model follows a bottom-up approach, in which the role of agents play an important role in determining the system outcomes, subject to some regularities at the macro level [184]. Because of these previous characteristics, an agent-based model is a suitable methodology to study the design of balancing rules. In electricity balancing, the balancing rules are the regularities set at the macro level and an agent-based model can help to understand the BRP/BSP behaviors in relation to the established rules.

In electricity balancing, van der Veen et al. [118] applied an agent-based model to study the impact of different imbalance pricing in the overall system costs. The approach presented in this chapter differs from them as the main focus of this approach is on cross-border effects of different imbalance pricing rules, while van der Veen et al. [118] only focus on national markets. Additionally, van der Veen et al. [118] do not model the day-ahead market or the forecast errors from intermittent RES-E. These aspects are relevant to understand the electricity systems with high penetration of intermittent RES-E and they are included in the present model.

Vandezande et al. [175] analyzed the effect of cross-border strategies of different imbalance pricing mechanisms. They show, through statistical analysis of market prices, that static strategies between France and Belgium in 2008 can be profitable because of the imbalance pricing schemes applied in these countries. However, Vandezande et al. [175] used a static analysis with a single strategy for the whole year, while strategies can change from hour to hour. This dynamic behavior is represented through the agent-based model presented in this section.

8.4.2 Model objective

The model consists of two interconnected systems with different imbalance pricing mechanisms. In addition, companies with different generation mixes are modeled. Furthermore, companies with units in the two neighboring countries may arbitrate between both countries to trade expected energy imbalances. The effect of different imbalance pricing on the behavior of multinational companies in multinational electricity markets has not been studied in the literature.

8.4.3 Model structure

The model presented in this section was developed in collaboration of master students, Malte Rödl and Selin Saygili, as part of the course “Agent Based Modeling of Complex Adaptive Systems” taught by Dr. Igor Nikolic from Delft University of Technology. The students worked under close supervision of José Pablo Chaves Ávila, who was involved in the whole modeling process[4]. This model was developed in NetLogo.

Model assumptions

Electricity balancing modeling is a complex task due to the different details of the system and actor behaviors. But the purpose of the model is to show the effect of different imbal-

[4]The full model description and the code can be found in http://wiki.tudelft.nl/bin/viewauth/Education/SPM955xABMofCAS/StudentPag

ance prices mechanisms, despite of other details of electricity markets. Therefore some of the assumptions of the model are the following:

- Only two markets are considered. These markets have similar generation mixes in order to isolate the effect of flexibility options between them.
- There are four generation technologies: wind, nuclear, coal and gas. The generation mix and power plants ownership are based on the actual Dutch electricity data[5]. Four generation companies are assumed to participate in both markets with equal market share.
- Technical characteristics of power plants such as ramp rates, start-up and shutdown costs are not considered. This implies that the traded hours are independent from each other.
- The grid is not included in this model. More complex bidding strategies with grid can be considered, as suggested in Chapter 5.
- Balancing capacity is priced at 10% of the fuel costs; this is equal for all the companies.
- The market is supposed to be competitive and generation companies bid their marginal costs.
- Demand is inelastic and external to the generation companies' decisions.
- Demand and wind energy forecasting is done centralized and homogeneous distributed between the companies. In reality, there are geographical characteristics of wind energy sources that are not considered in the model.
- There is no information asymmetry between market parties.

Actor identification

The main agents are four generation companies, which have both roles of BRPs and BSPs. They can bid in the day-ahead market and provide balancing services. These companies are fully responsible for their energy imbalances.

The market and system operators are the same entity who run both the day-ahead and the balancing markets.

Consumers are passive agents, price-takers and pay the electricity costs, both energy and balancing costs.

The regulator is an agent who is able to set different imbalance pricing mechanisms.

Environment

Variables such as forecast errors for demand and wind, fuel prices and generation outages and time of the markets are part of the environment. Fuel prices and outages rates are based on those used by Chappin [37]. Fuel prices are assumed to be: 38.605 €/MWh (gas), 32.727 €/MWh (coal) and 9.007 €/MWh (nuclear).

[5] Power plants data are available in http://enipedia.tudelft.nl/

Model flow

Figure 8.4.1 shows the model flow for the agent-based modeling.

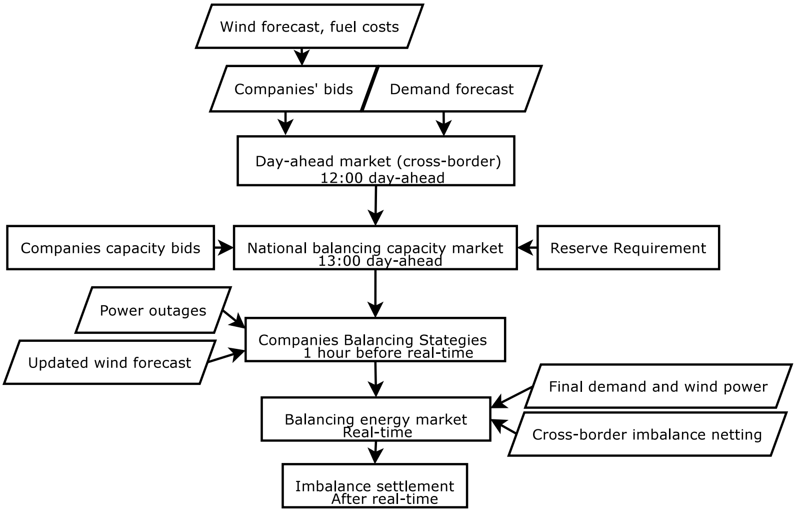


Figure 8.4.1: Agent-based model flow

At first, wind and demand forecast are calculated, which are delivered to the system operator as well as the companies. The companies submit bids to the day-ahead market, based on fuel costs and wind energy forecast.

Then, the joint day-ahead electricity market is executed. This is based on equal shares, which is a simplification that means that every company can bring the same percentage of its portfolio (for the respective energy source) to the market. For example, if 100 MW are needed, and 200 MW are available at the same price, every company can bring 50% to the market. If all the resources from the same country are used, resources of the other country could also be taken as long as they are available, as an effect of the joint market. The day-ahead market clearing is based on the marginal costs.

After the day-ahead market is cleared, the balancing capacity market is executed at the national level. For this, at first the reserve requirements have to be calculated. They are usually based on the share of wind energy as well as on the demand and the biggest plant connected to the grid. For the balancing capacity market itself, wind energy cannot provide this service.

Then, it might happen that power outages occur. Outages can occur for a single plant, a network connection or theoretically even by a lack of fuel. Outages are assigned to the portfolio of each generation company.

An important part of the model is the balancing of multinational companies. This happens one hour before real-time. The goal for these companies is to avoid high imbalance costs or to benefit from imbalance prices. For this, the total net balance of the company is calculated and determined whether the countries' markets have a surplus or deficit. The latter are estimations of the company, as each company only knows the updated wind forecast, but not outages of other companies. Then, the company has to decide, what to do with its surplus or deficit of electricity.

Multinational companies decide their strategies to reduce imbalance costs based on previous market results, expected energy and expected imbalances prices. In general terms, if the company has a net deficit, the company reduces its deficit in the country with high imbalance prices. Whereas if the company has a net surplus, the company increases the imbalance in the country with higher imbalance prices. The amount of energy traded is then virtually shifted through the corresponding system. Further imbalanced positions are net also between the countries.

In real time, the System Operator has to balance the electricity system. If there is a system deficit, balancing capacity is activated, whereas if there is a energy surplus, then generation needs to be reduced.

Finally, system imbalances and imbalance prices are calculated, and the finances of the companies and the system operators are updated. All energy is rewarded, including imbalances, upscale availability, as well as fuel costs.

Imbalance pricing mechanisms

The main design variable tested in this model is the imbalance pricing mechanisms, which can be changed by the national regulators. The resulting imbalance price can have four combinations based on the following pricing rules:

- Marginal pricing. When the marginal pricing rule is used the price of the most expensive activated energy bid is applied as the imbalance price.
- Average pricing. The volume-weighted average price of activated reserves is applied as imbalance price.
- Single pricing. With single pricing, the same price is applied for both positive and negative imbalances.
- Dual pricing. In dual pricing, if the imbalances are in the same direction of the system, then the day-ahead price is applied. In case of opposite direction, the prices of activated reserves are applied (marginal or average).

Table 8.7 shows examples of the different European countries that apply different combinations of imbalance pricing rules previously explained. These countries are interconnected with the Netherlands and with intraday trading possibilities among them. This allows market parties, present in the different countries, to arbitrate between the different pricing rules to decrease their imbalance costs. However, by doing this, the total system imbalance in one of these countries can be negatively affected.

Table 8.7: Examples of imbalance pricing rules applied in some European countries

	Marginal Pricing	Average Pricing
Single Pricing	Netherlands	Germany
Dual Pricing	Nordic Region	Great Britain

Model verification Different steps are performed to verify that the model performs as expected. The check was performed changing different system variables, like the wind generation, testing the availability of the power plants, and tests on cross-border electricity trade flows, among others. After executing different tests, some errors were fixed.

8.4.4 Model Results

The model is run for an entire month of 720 hours, simulated 200 times. Two energy scenarios are performed, one that represents environment generation mix of the Netherlands and an additional one that assumes 50% wind of total installed capacity.

Figure 8.8 shows the difference (hourly average) between national and multinational companies by applying different pricing mechanisms. The multinational companies have generation units in both countries and can trade between them. In general, when imbalance prices differ between countries, multinational companies can profit more from cross-border electricity trade in comparison with national companies. For both scenarios, lower profits occur when imbalance prices mechanisms are the same for both countries.

Table 8.8: Profit differences (hourly average) between national and multinational companies under different pricing rules

(a) Current Dutch generation scenario

			Market A			
			Average Pricing		Marginal Pricing	
			Dual	Single	Dual	Single
Market B	Average	Dual	0.37	0.26	1.13	1.91
		Single	1.25	0.86	1.72	0.75
	Marginal	Dual	-0.08	0.54	0.94	1.01
		Single	2.10	1.60	2.08	0.43

(b) 50% wind installed capacity

			Market A			
			Average Pricing		Marginal Pricing	
			Dual	Single	Dual	Single
Market B	Average	Dual	4.68	6.14	5.12	5.05
		Single	9.10	4.58	6.27	1.89
	Marginal	Dual	5.23	6.17	-3.21	7.85
		Single	5.01	3.89	5.80	5.33

Differences in imbalance pricing mechanisms also have an impact on the net revenues (income minus cost) of System Operators. This is an important output of the model because depending on the imbalance pricing mechanisms, multinational companies can trade and increase the system imbalance (and costs) in one of the countries. Table 8.9 and Table 8.10 show the differences in System Operators' profits by applying different imbalance pricing mechanisms. These tables show the change in System Operators revenues from cross-border electricity trade versus not allowing trade between the countries. Positive values mean that the System Operator increases its income in comparison with the non-trade situation, the opposite correspond to negative values.

Table 8.9: Hourly System Operators' income difference with different imbalance pricing rules (current Dutch generation scenario)

(a) TSO A

			Market A			
			Average Pricing		Marginal Pricing	
			Dual	Single	Dual	Single
Market B	Average	Dual	27.73	61.64	-52.16	17.36
		Single	-55.24	0.72	-47.98	-2.66
	Marginal	Dual	5.02	22.25	1.15	10.38
		Single	-73.89	6.53	-35.83	-0.64

(b) TSO B

			Market A			
			Average Pricing		Marginal Pricing	
			Dual	Single	Dual	Single
Market B	Average	Dual	22.22	-71.08	-20.40	-32.85
		Single	37.73	17.00	35.71	-12.50
	Marginal	Dual	-28.01	-53.48	-5.16	1.78
		Single	29.91	13.75	47.94	1.71

Table 8.10: Hourly System Operators' income difference with different imbalance pricing rules (50% wind installed capacity)

(a) TSO A

			Market A			
			Average Pricing		Marginal Pricing	
			Dual	Single	Dual	Single
Market B	Average	Dual	59.10	88.69	33.58	29.26
		Single	23.68	34.64	28.98	23.34
	Marginal	Dual	-8.88	140.28	20.87	55.51
		Single	-7.53	63.55	23.85	42.79

(b) TSO B

			Market A			
			Average Pricing		Marginal Pricing	
			Dual	Single	Dual	Single
Market B	Average	Dual	34.16	35.94	17.65	15.22
		Single	43.69	45.26	71.23	52.79
	Marginal	Dual	58.51	18.34	63.19	-20.57
		Single	79.08	62.27	83.12	37.05

As expected, for the 50% wind installed capacity, the cross-border trade has higher impact on the SO revenues than the current Dutch generation scenario. This is in line with the previous results for the companies with cross-border electricity trade. For both scenarios, the model results show that when both countries apply the same imbalance pricing mechanisms the SOs' net income is reduced. This is specially the case when both countries apply marginal pricing.

When one country applies dual pricing and the other one applies single pricing, the SO from the country with single pricing has a reduction in their revenues in favor of the TSO of the country with dual pricing. This is because companies that are present in both countries try to reduce their imbalance in the country with dual pricing, impacting negatively on the imbalance (and costs) of the country with single pricing.

8.5 Conclusions

European institutions are currently designing the Network Code on Electricity Balancing [5, 4]. In these proposals European policy makers are fostering the interchange of balancing services between countries. ACER [5] and ENTSO-E [6] have important proposals for the harmonization of technical aspects and institutional designs of balancing mechanisms. However, these European institutions provide general guidelines that give flexibility to national authorities to set different regulations, which can lead to inefficient trading between countries.

Northwestern European countries currently trade electricity cross-border through intraday markets. In addition, some of these countries currently exchange (net) energy imbalances. Furthermore, these countries are expected to increase further short-term cross-border electricity trading through intraday markets with more efficient methods for the allocation of intraday transmission capacity and through the exchange of balancing services in multinational markets.

Although harmonization of balancing mechanisms brings different challenges, an effort to harmonize these mechanisms could contribute to improve economic efficiency in Europe. The harmonized design can be based on those designs that guarantee economic efficiency and flexibility in the balancing mechanisms. This flexibility can be provided, for instance, by cross-border market mechanisms with a single gate closure time close to real time for each of the different short-term markets: intraday, balancing capacity, balancing energy.

The pricing mechanisms for balancing services and imbalances play an important role in reflecting efficient price signals and avoid adverse incentives for market parties. Prices based on the marginal pricing rule give a transparent mechanism and efficient signal to the market. This becomes more relevant with increasing intermittency in power systems.

Transparency of the balancing mechanisms is improved by the publication of prices and volumes of procured and activated balancing services as they are closer to real time, which provides more information to market parties to avoid imbalance costs.

The current changes in the generation mix as a result of the penetration of intermittent RES-E increase network congestions. Therefore, in this context, locational price signals may become necessary to improve economic efficiency.

A single European market design for short-term market mechanisms ensure that economic benefits from cross-border electricity trade are maximized, which is more relevant with power systems with large penetration of intermittent RES-E. The agent-based model shows that the same imbalance pricing mechanisms for both countries reduces the net revenue transfer from one System Operator to another. In addition, differences in imbalance pricing mechanisms increases the possibilities for multinational companies to increase their revenues from cross-border electricity trade with higher costs for the System Operators and consumers from one of the countries.

Chapter 9

Conclusions and recommendations

9.1 Conclusions and answers to research questions

This thesis explores the adequacy of European short-term electricity market designs to efficiently integrate intermittent renewable energy sources into electricity systems, especially wind power. One of the general findings of this thesis is the strong interaction between different short-term markets and balancing mechanisms. This thesis has proven that some of the established recommendations in the literature and current national regulations were not necessarily correct mainly because of the neglect of interrelations between the various short-term market mechanisms. Although most of the analyses presented in this thesis are case dependent on the system and market in consideration, some general insights are useful for the market designs in a European wide context. Based on those analyses, this thesis identifies some of the best practices which are applicable for the European market design. This thesis also highlights some of the main challenges for future research.

Intraday markets

In Europe there are two intraday market designs: discrete auctions (applied in the Iberian market) and continuous trading (applied in Northwestern Europe). The Spanish intraday market has been signaled by the literature as a good design that provides high liquidity. However, this thesis reveals that this is not only due to the discrete auction design by itself but also due to specific market regulations applied in the Spanish market, such as the dual imbalance pricing mechanism (that strongly penalized energy imbalances), the allocation of balance responsibility to all market parties (including all renewable sources), and unit scheduling instead of portfolio balancing.

Changes in support schemes have a significant impact on the incentives for market parties to trade in the intraday market. By analyzing data from the Spanish market, the change from feed-in premium to feed-in tariff has substantially decreased the participation in the intraday market. In addition, with the feed-in premium scheme, market parties arbitrated between the day-ahead and intraday markets. This is partially due to the design of congestion management mechanisms, which allows market parties to bid systematically lower in the intraday market.

By contrast, intraday continuous trading differs significantly with discrete auction design. Based on German intraday market data, market parties trade closer to the market closure more than at the beginning of the market. In addition, bidding prices change during the whole trading period, where sellers start bidding at high prices and decrease bid prices in later trading hours, as they approach market closure. In Germany, with the change from feed-in tariff to feed-in premium (opposite to the Spanish case), the use of balancing energy by the System Operators has changed from having a clearly biased strategy before the introduction of feed-in premium option to a more neutral use of balancing services after the feed-in premium implementation.

This thesis describes that in continuous trading, pricing of cross-border transmission capacity in case of congestions is not straightforward to compute. In this respect, this thesis proposes general principles to be considered when designing cross-border transmission capacity.

Finally, this thesis proposes the implementation of financial arbitraging between the day-ahead and intraday markets (known as convergence bidding). Convergence bidding policy applied in USA markets has been a successful to achieve price convergence between short-term markets, increase liquidity in these markets and improve general economic efficiency. Although the European electricity market designs differ from those of the USA, the implementation of convergence bidding is possible and it can be beneficial in terms of market efficiency and to increase balancing alternatives for intermittent RES-E. Based on the analysis of price data from the Spanish and German markets, convergence bidding is concluded to be an attractive policy for the implementation in these markets.

Intraday cross-border trade impact on wind power balancing

This thesis analyzes bidding strategies for a Dutch wind power producer (WPP) that participates in the Dutch day-ahead market, the German intraday market and adjusts the power dispatched. The model uses different intraday forecasts for prices and power to compare the impact of forecast improvements in different time frames. Additionally, it incorporates liquidity risk measures of not getting all bids accepted in the intraday market. The expected profits of the proposed model with the intraday possibilities could have increased the WPP profits from 7% to 17% during December 2010, depending on the forecasting time and liquidity assumptions.

With the imbalance settlement applied in the Netherlands, WPPs are incentivized to create intentional imbalances to maximize their profits and take advantage of favorable imbalance prices. Additionally, it has been also shown that negative imbalance prices for long positions will encourage WPPs to reduce generation, if they had a long position. Certainty of imbalance prices is crucial to reduce imbalances costs. In the Dutch case, TenneT publishes information every minute about the system balance and the marginal price of the last activated balancing energy bids. Thereby, this information gives valuable signals to forecast imbalance prices and adjust generation. This real-time imbalance price information together with the imbalance pricing incentivizes market parties to react to the system imbalance.

The current allocation of intraday interconnection capacity between the Netherlands and Germany (first-come, first served) is not an efficient way of allocation and pricing of cross-border intraday capacity. The further integration of national intraday markets in Europe, with implicit allocation of interconnection capacity, would increase liquidity, give better valuation of intraday interconnection capacity scarcity and decrease imbalance costs associated with the integration of intermittent RES-E.

Participation of wind power in the European balancing mechanisms

The designs of balancing mechanisms can limit the possibilities of wind power to participate in these mechanisms. One limitation refers to the time frame of these mechanisms. However, participation of wind power in balancing mechanisms permits a comparison of its opportunity costs with alternative options in a market based approach. Wind power can provide potential benefits for both system balancing services and congestion management purposes. Specifically, the participation of wind power, in case of downward regulation when thermal plants face higher costs to decrease their generation, can be economically efficient. Upward regulation bids might allow wind power to reveal information of updated wind energy forecasts, and it can decrease balancing requirements. From the countries analyzed, only Denmark allows direct participation of wind power in the balancing market and wind power has been active in this market. In Great Britain, some wind units can participate, but it is not extended to all units.

From the system security and wind power producers' perspectives, there are some risks involved in the participation of wind power in balancing markets which are associated with inaccurate forecasts. Therefore, imbalance prices should be cost reflective to avoid potential gaming in balancing markets, as bid quantities will depend on energy forecasts, which cannot be easily verified by the System Operator. Additionally, the payment for the provision of balancing services by wind power should be capped by opportunity cost to avoid possible adverse incentives.

The interplay between congestion management and imbalance prices

The increasing penetration of intermittent RES-E requires a proper functioning of the balancing mechanism, as these sources are a major cause of network congestions and energy imbalances. Since imbalance prices incentivize market parties to submit accurate energy schedules and support the system balance in real-time, the imbalance pricing mechanism should be designed to give correct incentives to market parties.

In the last years, the German balancing design has been evolving, but still there are design elements of concern in terms of short-term efficiency: the time at which reserve bids becomes final is long before the time of dispatch (week ahead for FRR), the pay-as-bid pricing structure of reserves (both capacity and energy components) and imbalance prices based on the average energy costs of these reserves, among others. In addition, the German imbalance pricing mechanism can give adverse price signals in the presence of network congestions.

Moreover, congestion frequently occurs within the German electricity system which, under certain circumstances, provides incentives for market parties to deviate from the energy schedules in the opposite direction of the system imbalance (increasing the local energy imbalance). To mitigate congestion among German control areas, the system operators activate reserves out of the common merit order for the whole country. Market parties may assess, based on the data published by the system operators close to real time, when imbalance prices can make it profitable to deviate from the energy schedules. Furthermore, market parties that participate in the reserve market have more information to react to the imbalance prices, which leads to unequal market conditions.

Alternative designs for the imbalance pricing mechanisms can avoid gaming opportunities in case of network congestions. The nodal single imbalance pricing mechanism provides locational price signals of balancing costs and avoids the aforementioned adverse price signals. However, the nodal imbalance pricing mechanism also requires nodal day-ahead and intraday prices, otherwise additional inefficiencies may emerge. However, the implementation of nodal pricing implies a significant change in the market design, which aggravates the technical complexity of the system. Moreover, the issue of nodal pricing is a politically sensitive issue in Europe.

Without applying nodal pricing, a second best option based on the mix of single and dual imbalance pricing mechanisms, may avoid adverse price signals in the current imbalance pricing mechanism in Germany. For hours without congestions (or very few congestions), a single imbalance pricing mechanism can be applied, preferably based on marginal costs of balancing energy (requiring a balancing energy pricing mechanism to be changed from pay-as-bid to marginal pricing). In case of congestions, and activation of both upward and downward regulation, dual pricing prevents adverse incentives that may worsen the local energy imbalance. This design may be suitable for other European countries that have similar market designs (national prices for spot markets and energy imbalances) and are confronted with a likely increase in internal network congestions due to the increase of intermittent RES-E in their systems.

Alternatives for the European priority dispatch rule for RES-E

According to the European Commission, the priority dispatch rule for RES-E is no longer required. However, it has been already granted for existing units. In case it has to be changed there are different design aspects that need to be considered. This thesis discusses some of those relevant aspects and measures their impact in the Spanish case study in the 2020 scenario.

The priority dispatch rule, as currently implemented in the Spanish market, does not isolate the volume risk of renewable generators as they face curtailment costs with relative low compensation. The Spanish market currently has a price floor of zero in all markets. Because of this, zero prices are significantly more frequent than in other markets with high penetration of intermittent RES-E.

The lack of negative prices has significant implications for the system efficiency. First, it does not allow discriminating between different types of inflexibility, such as the inflexibility of thermal units, inelastic demand or transmission capacity. For new installations, investment signals are distorted, as new units do not properly face market risks. In addition, storage facilities and demand response programs cannot respond to proper price signals if negative prices are not allowed.

The operational model for the Spanish scenario shows that, by removing the priority dispatch and allowing negative prices, the costs for consumers are reduced and the revenues of existing intermittent RES-E based generators are almost not affected in comparison with the current situation. This implies a gain in economic efficiency for the whole system. Moreover, with the proposed changes the short-term price signals of inflexibility are reflected. Future renewable installations are expected to receive lower levels of support schemes than existing ones because of technological improvements. With the introduction of negative prices, existing installations can bid higher negative prices, which correspond to the support schemes with negative sign.

The model results show that with negative prices and without the priority dispatch, curtailment for existing units is reduced and the total revenues for these units can slightly increase. New installations will face higher curtailment with negative prices, even when considering demand response. Although the model does not represent the grid, future installations, by facing higher curtailment risk, may have incentives to locate in areas where potentially curtailment can be reduced. To compensate for higher risks of curtailment, new installations may require curtailment compensation, but this compensation should give locational signals. If curtailment compensation is not provided, more generous support schemes might be required to compensate for the curtailment risk.

Balancing rules impacts on bidding strategies for wind power

This thesis computed the economic impact (and market signals) of different balancing rules applied in four European countries (Belgium, Denmark, Germany and Netherlands), by using a stochastic optimization model, which incorporates relevant uncertainties that affect the participation of wind power producers in electricity markets. The model results outperformed those obtained by bidding the expected energy in the markets, which validates the model usefulness. The model shows that balancing rules have a significant impact on the profits of wind power producers, on bidding strategies and on final energy imbalances. Furthermore, these short-term balancing rules can have an impact on system operational costs and even on investment signals.

The model results show that wind power producers, in order to maximize their revenues in the short-term markets, can arbitrate between the different markets. The bids in these markets do not necessarily correspond to the expected energy, but they also depend on the price forecasting and rules related to the allocation of balance responsibility and the imbalance pricing mechanisms in place. In addition, the application of single or dual pricing does not ensure that wind power producers bid the expected energy, as generators would hedge against the expected imbalance prices.

Based on the model results, single pricing gives a higher income to wind farms, but also leads to higher energy imbalances. In addition, even within the single pricing design, there are different design options to compute imbalance prices, for example those prices can be based on the marginal activated balancing energy bids (Belgium and the Netherlands) or based on the average costs (Germany). Single pricing based on marginal activated balancing energy bids gives the marginal price signal of system cost of additional imbalances, which is a stronger incentive to avoid energy imbalances in the same direction of the system than the imbalance prices based on average cost. In addition, the allocation of balance responsibility to wind power producers should be considered together with the imbalance pricing design. In the German case, the single pricing based on the average energy cost of reserves can increase the energy imbalances, which can have a negative impact on the system balancing costs.

As discussed earlier, balancing regulations are interrelated (e.g., the allocation of balancing responsibility and imbalance pricing) and should be considered together. The quantitative analysis shows that in the Belgian case, the tolerance margin can represent a penalization instead of a potential benefit for wind power producers. That is due to the change of the Belgian imbalance pricing from dual pricing to single pricing.

The publication of system imbalance and imbalance prices close to real time is an important element to reduce system imbalances in case of excess of generation and existence of negative imbalance prices. In Germany, imbalance prices are published with a month of delay. It does not allow market parties to react to negative imbalance prices. This reaction is possible in the Netherlands and Belgium, as these countries publish the system imbalance and imbalance prices every minute and two minutes, respectively. In Denmark, this publication is done within an hour.

With respect to the imbalance subsidies (applied in Denmark and Germany), they effectively increase the feed-in premium as they are given per megawatt hour delivered. These subsidies limit the reaction of wind power producers to negative prices by the amount of the subsidy. In the German case, this subsidy represented a significant part of the estimated income for the year 2012, which might have resulted in windfall profits for wind power producers.

The System Operators should be aware of the economic incentives that intermittent RES-E have and incorporate those incentives in the operation of the system, which is becoming more challenging. Furthermore, the design of balancing rules should be considered in the design of the support schemes, as they can significantly impact the revenues of renewable sources, especially those that are intermittent, such as wind and solar power.

Effect of lack of harmonization of European balancing rules

European institutions are currently designing the Network Code on Electricity Balancing [4, 5]. In these proposals European policy makers are fostering the interchange of balancing services between countries. ACER [5] and ENTSO-E [4] propose guidelines for the harmonization of technical aspects and institutional designs of balancing mechanisms. However, these European institutions provide general guidelines that give flexibility to national authorities to set different regulations, which can lead to inefficient electricity trade between countries.

Although harmonization of balancing mechanisms entails many challenges, in the context of high penetration of intermittent RES-E, an effort to harmonize these mechanisms could contribute to improve the economic efficiency of the electricity system in Europe. The harmonized design should be based on those designs that guarantee economic efficiency and flexibility in the balancing mechanisms. This flexibility can be provided, for instance, by cross-border market mechanisms with a single gate closure time close to real time for each of the different short-term markets: intraday, balancing capacity, balancing energy.

The pricing mechanisms for balancing services and imbalances play an important role in reflecting efficient price signals and avoiding adverse incentives for market parties. Prices based on the marginal pricing rule give a transparent mechanism and efficient signal to the market. This becomes more relevant with increasing intermittency in power systems.

The timely publication of prices and volumes of procured and activated balancing services improve transparency of balancing mechanisms. This provides incentives to market parties to react to system imbalance and reduce imbalance costs.

The current changes in the European generation mix as a result of the penetration of intermittent RES-E increase network congestions. Therefore, in this context, locational price signals may become necessary to improve economic efficiency.

By using an agent-based model that represents two neighboring countries and companies with units in both areas, when the same imbalance pricing mechanism is applied the transfer of revenues from one System Operator to another is reduced. In addition, differences in imbalance pricing mechanisms increase the possibilities for multinational companies to increment their revenues from cross-border electricity trade, with higher costs for the System Operators and consumers from one of the countries.

9.2 Recommendations for policy makers

This thesis provides some insights to European policy makers (national and those at the European level) for the design of short-term electricity market mechanisms. With the increasing penetration of intermittent RES-E, short-term market mechanisms play an important role to ensure the efficiency and security of the systems. The short-term market mechanisms should provide flexibility to adapt the markets and system operation to the limited predictability of intermittent RES-E.

European policy makers should avoid any distortions in the different markets, otherwise negative effects can arise in terms of economic efficiency and security of the system. In addition, market mechanisms should allow inflexibilities from different sources to be reflected through marginal market prices, without any discrimination between generation or consumption units. Hence, market parties can react to those price signals that efficiently reflect the balancing costs of the systems.

European policy makers should be aware of the interrelations between different short-term market mechanisms, as changes in any one of them will affect the others. This thesis provides different examples of the importance of these interrelations, for example, between the allocation of balance responsibility and the design of imbalance pricing, or between network congestions management and the design of the imbalance prices. In addition, as shown in the Spanish case, the intraday market and different balancing mechanisms are strongly interrelated. Distortions in these mechanisms create opportunities for market parties to profit with negative impact on the system costs. Furthermore, System Operators should be aware of the bidding strategies of market parties in the various short-term markets and adapt their management of system operations accordingly. This task is becoming more difficult as more intermittent RES-E are entering the markets, each reacting differently based on their own energy and prices forecasts, bidding strategies, among other economic incentives.

Harmonization of the short-term market mechanisms is beneficial for the whole European system. It guarantees that cross-border exchange of electricity increases economic efficiency. The current objectives of ENTSO-E and ACER, in terms of harmonization of balancing mechanisms, are not very ambitious and give ample freedom to the national authorities to choose their national designs. This lack of pressure of harmonization of national market designs may imply the preservation of current differences, which limits the potential efficiency gains from cross-border electricity trade. In different aspects, ENTSO-E and ACER set the boundaries lower than current best practices.

9.3 Future Work

Due to time limitations, various aspects of interest for further developments of the European short-term electricity markets have not been addressed in this thesis, resulting in the following recommendations for future research:

Intraday markets

With respect to the intraday market design, it is required to define a price mechanism for cross-border transmission capacity in continuous trading, which is the design chosen for implementation in Europe. This thesis provides general guidelines for this, but the modeling of alternative options is required, for instance through an agent-based model. In addition, if discrete auctions remain in some markets (Iberian and Italian), potential losses of economic efficiency caused by having both designs need to be further explored.

This thesis also proposes the implementation of convergence bidding for Europe for the day-ahead and intraday markets, in order to increase liquidity in the latter. However, implementation requirements still need to be explored as well as the extension to other markets for balancing services.

Bidding strategies

A better characterization of bidding strategies in a continuous intraday market is needed, as price formation in continuous intraday markets substantially differs from discrete auctions. Furthermore, due to frequent changes in regulations with respect to renewable sources these strategies need to be updated to regulatory changes. A detailed analysis of price dynamics needs to be considered for cross-border continuous intraday market.

With respect to the modeling of bidding strategies used in Chapters 3 and 7, further research might consider removing some simplifying assumptions such as dependency between wind power errors and intraday prices or imbalance prices. Such dependency is especially significant for systems with a high penetration of wind power (the case study in this thesis only considered a single offshore wind farm, assuming it does not have an impact on market prices). Additionally, wind power generation units might be part of a generation portfolio, with other generation units, that can be used strategically. In order to consider the influence of market prices, a non-linear approach can be used to compute prices and quantities (the problem then turns into a nonlinear formulation, which is computationally more complex). In addition, more information on intraday bids is required, which are not publicly available but can be possibly obtained through collaboration with power exchanges.

The strategic bidding models in this thesis assume that the wind farm is small and does not affect market prices. However, further research should consider different sizes of generation units that have similar bidding strategies. In addition, geographical dispersion of wind farms should be included, as it may considerably reduce forecast errors.

Increase of solar power installations

The main focus of this thesis has been on wind power. However, investments in solar photovoltaic are also expected to increase significantly due to drastic cost reduction of this technology. Further research should analyze more in detail how specific features of PV solar power differ from those of wind power and what implications this would have for the design of short-term market mechanisms.

System operation including bidding strategies of intermittent RES-E

This thesis has shown (by using model results and empirical data analysis) that intermittent RES-E based power producers may exhibit profit maximizing bidding behavior, in which they deviate significantly from their energy forecasts. In systems with a high penetration of these sources, the system operation hence becomes more challenging. Future system operation should include uncertainties about market parties' strategies in markets. This leads to more complicated operation of the system, as uncertainties about intermittent generation are not only resulting from energy forecast errors but also due to market parties' strategic behavior, the patterns of which are likely to be different for different RES-E.

An additional interesting aspect to investigate is to compare how internal balancing (balancing within the generation portfolio of one and the same power producer) can affect the overall efficiency of the system in contrast with balancing through the market. Losses in economic efficiency can be expected from internal balancing strategies, as imbalances can be compensated within the larger system at lower costs.

Further development of an agent-based model to explore the effects of lack of harmonization of balancing rules

The presented agent-based model in this thesis is a first step to measure the effect of different pricing schemes. This model relies on simplifying assumptions; further research should consider the removal of those assumptions, like the modeling of technical constraints of power plants or grid representation. An agent-based model can be a useful tool to understand different market parties' strategies in the short-term electricity markets. Further developments should also consider other important design variables of balancing mechanisms.

Appendices

Appendix A

Acronyms

ACER	Agency for the Cooperation of Energy Regulators
APX	Amsterdam Power Exchange (Dutch-British power exchange)
CNMC	Comisión Nacional de los Mercados y la Competencia (Spanish Market and Competition Regulator)
CRE	Commission de régulation de l'energie (French Energy Regulator)
DA	Day-ahead
EC	European Commission
ENTSO-E	The European Network of Transmission System Operators for Electricity
EPEX	European Power Exchange (power exchange for Germany, France, Switzerland and Austria)
EU	European Union
FRC	Frequency Containment Reserves
FiP	Feed-in premium
FiT	Feed-in tariff
FRR	Frequency Regulation Reserves
ID	Intraday
IM	Imbalance
MO	Market Operator
MW	Megawatt
MWh	megawatt hour
OMIE	Operador del Mercado Ibérico Polo Español, S.A (Iberian market operator)
PTU	Program Time Unit
REE	Red Eléctrica de España (Spanish TSO)
RTE	Réseau de transport d'électricité
SO	System Operator
STU	Settlement Time Unit
TSO	Transmission System Operator
UCTE	Union for the Coordination of Transmission of Electricity
RES-E	Renewable energy sources for electricity
RR	Replacement Reserves
WPP	Wind Power Producer

Appendix B

Nomenclature

Indexes

h:	Hour under consideration
ω:	Scenario
N_T	Total number of hours
N_Ω	Total number of scenarios

Parameters

$\lambda^{DA}_{h\omega}$, $\lambda^{I}_{h\omega}$	Day-ahead and intraday prices, respectively
$\lambda^{+}_{h\omega}$, $\lambda^{-}_{h\omega}$	Imbalance price for positive and negative deviations, respectively
P^{max}	Maximum power that can be sold in the market (wind farm installed capacity)
$IntCap_{(GE-NL)h\omega}$	Available intraday interconnection capacity between Germany and the Netherlands

Variables

$P^{DA}_{h\omega}$, $P^{I}_{h\omega}$	Power sold in the day-ahead and intraday market, respectively
$\Delta^{+}_{h\omega}$, $\Delta^{-}_{h\omega}$	Positive and negative deviations, respectively
$\Delta_{h\omega}$	Net sum of imbalances
$\Delta^{+}_{1h\omega}, \Delta^{-}_{1h\omega}$	Positive and negative imbalances (respectively) higher than 30% of the nominated energy (Belgium)
$P^{S}_{h\omega}$	Sum of the power bid in the day-ahead and intraday markets
$P_{h\omega}$	Power delivered
$\alpha_{h\omega}$, $\beta_{h\omega}$	Binary variables active when positive and negative imbalances are higher than 30%, respectively (Belgium)
$\gamma_{h\omega}$	Binary variable active in case of positive imbalances
$Y_{h\omega}, X_{h\omega}$	Continuous variables necessary for the model linearization

Appendix C

Definitions

The definitions provided are the author's own adaptation mainly based on the European Network Codes [4, 185] and definitions used by van der Veen [10].

- Area Control Error (ACE): the instantaneous difference between the actual and the scheduled value of the power interchange of a control area with the rest of the synchronous zone. It incorporates the effect of Frequency Containment Reserves.
- Balance responsibility: financial responsibility for a Balance Responsible Party for energy imbalances over the Settlement Time Unit.
- Balance Responsible Party (BRP): a market party that is responsible for submitting energy schedules (for generation, consumption and/or trade) to the System Operator, and is financially responsible for energy imbalances.
- Balancing: actions taken by the System Operators to maintain the system frequency within a predefined stability range established in the European Network Code on Load- Frequency Control and Reserves.
- Balancing capacity: product that gives the obligation for a Balancing Service Provider to place balancing energy bids according to contractual specifications.
- Balancing energy: energy activated by the System Operator to balance the system.
- Balancing energy bids: a product on a Common Merit Order List that entails an option to deliver balancing energy.
- Balancing market: refers to the institutional, commercial and operational arrangements that establish market-based management for the function of Balancing within the framework of the Network Codes.
- Balancing capacity bids: the obligation of a Balancing Service Provider to place balancing energy bids according to contractual specifications.
- Balancing services: either balancing capacity or balancing energy.

- Balancing Service Provider (BSP): a market participant providing balancing services to its contracting System Operator.
- Balancing Service Provision: a mechanism which defines how different balancing services are bought and how the Balancing Service Providers are remunerated.
- Common Merit Order List: a list of all balancing capacity bids or balancing energy bids per standard product, sorted per direction (upward and downward regulation) and in order of their bid prices, used for the activation of balancing energy or procurement of balancing capacity.
- Control area: a power system area for which a separate system balance is maintained using a Load-Frequency Control.
- Downward regulation: net decrease of balancing energy activation obtained by a decrease in generation or an increase in consumption.
- Energy imbalance: energy volume calculated for a Balance Responsible Party, which corresponds to the difference between energy schedule and the final energy exchange, within a given Settlement Time Unit.
- Energy schedule: planned energy fed into/out of the grid over all Settlement Time Unit submitted by a Balance Responsible Party to the System Operator.
- Frequency Containment Reserves: balancing services used to stabilize the System Frequency after a disturbance.
- Frequency Restoration Reserves: type of balancing service used to restore the system frequency, and to remove the Area Control Error. It replaces Frequency Containment Reserves, so that these become available again for balancing. These reserves have an alternative name of secondary reserves.
- Gate Closure Time: is the time period until which balancing energy bids or balancing capacity bids can be submitted by the Balancing Service Provider.
- Imbalance costs: costs faced by Balance Responsible Parties resulting from imbalance settlement.
- Imbalance price: is the price computed per energy imbalances computed for each Settlement Time Unit.
- Imbalance settlement: financial settlement mechanism aiming at charging or paying Balance Responsible Parties for their energy imbalances.
- Load-Frequency Control: a central control used by a System Operator to activate Frequency Restoration Reserves in order to restore the system frequency.
- Long position: a positive energy imbalance, as a result of a reduction in consumption or an excess of generation from energy schedules.

- Network Code: set of rules drafted by ENTSO-E, with guidance from Agency for the Cooperation of Energy Regulators (ACER), to facilitate harmonization, integration and efficiency of the European electricity market.
- Network Code on Electricity Balancing: common rules for procurement, settlement and activation of balancing services.
- Network Code on Load-Frequency Control and Reserves: Network Code which defines the minimal requirements and principles for load-frequency control and reserves applicable to all System Operators, Distribution Operators and Balancing Service Providers.
- Passive balancing: intentional energy imbalances produced in order to profit from favorable imbalance prices.
- Regulator: an independent authority within a country who, among other functions, regulates the planning and operation activities of the grid operators in a national power system. Regarding the balancing market, the regulatory authority approves the balancing market rules proposed by the System Operator in the national code(s).
- Replacement reserves: reserves used to restore/support the required level of Frequency Restoration Reserves to be prepared for additional system imbalances.
- Short position: a negative energy imbalance, as a result of an excess of consumption or a generation deficit with respect to energy schedules.
- Settlement Time Unit: the time range at which energy imbalances are computed.
- Synchronous area: interconnected power system consisting of one or more control areas, in which a single system frequency is maintained.
- System frequency: the electric frequency in a synchronous area which is determined and controlled in the real time balance between system demand and total generation.
- System imbalance: the real-time power imbalance in a power system. In the imbalance settlement procedure, this concept refers to the net energy imbalance in the Settlement Time Unit.
- System Operator: is the entity responsible for the operation of the electricity system in a control area. The System Operator is in charge of the system security which includes, among other responsibilities, system balancing and congestion management.
- Upward regulation: net increase of balancing energy obtained by an increase in generation or a decrease in consumption.

Appendix D

Imbalance pricing mechanisms in European countries

This appendix describes the imbalance pricing mechanisms applied in selected European countries.

The common following nomenclature is used to define the different regulations. Any additional specific parameter is defined in the corresponding country description.

λ^{DA} :	Day-ahead prices
λ^{DW}_{av}:	Volume-weighted average price of downward activated balancing energy bids
λ^{UW}_{av}:	Volume weighted average price of upward activated balancing energy bids
λ^{DW}:	Marginal downward price of activated balancing energy bids
λ^{UW}:	Marginal upward price of activated balancing energy bids

Belgium

Belgium, from 2008 until 2011, applied dual pricing as described in TableD. 1.

Table D. 1: Imbalance pricing applied in Belgium, from January 2008 until December 2011

		Net Regulation Volume	
		Net Downward Regulation	**Net Upward Regulation**
BRP Imbalance	Positive	$min\left\{min\left[\gamma * \lambda_{av}^{DW} + \delta * \left(\lambda_{min}^{DW} - \lambda_{av}^{DW}\right)\right]; 0.91 + \lambda^{DA}\right\}$	$0.91 * \lambda^{DA}$
	Negative	$1.09 * \lambda^{DA}$	$max\left\{Max\left[\alpha * \lambda_{av}^{UW}; \lambda_{av}^{UW} + \beta * \left(\lambda_{max}^{UW} - \lambda_{av}^{DW}\right)\right]; 1.09 * \lambda^{DA}\right\}$

$\gamma = 0.905\, if\, \lambda^{DW} > 0$, $\gamma = 1.905\, if\, \lambda^{DW} < 0$; $\delta = min\,(1; GDV/450)$

$\alpha = 1.095$; $\beta = min\,(1; GUV/450)$

λ_{min}^{DW}, λ_{max}^{UW} are the minimum downward and maximum upward regulation prices, respectively.

GUV, GDV are the gross upward and downward regulation volumes, respectively.

Source: Elia [186]

In January 2012, imbalance pricing changed in Belgium (Table D. 2). It consists mainly of single pricing (based on the marginal prices of downward and upward activated bids) with an additional incentive applied in case of large system imbalances [167]. The incentive component is applied when the system imbalance is higher than 140 MW, which corresponds to the purchase of FRR. Additionally, from imbalance pricing shown in Table D. 2, there was a volume component equal to 0.1137€$/MWh$, which was removed on May 2013 [187].

Table D. 2: Imbalance pricing applied in Belgium since January 2012

		Net Regulation Volume	
		Net Downward Regulation	**Net Upward Regulation**
BRP imbalance	Positive	$\lambda^{DW} - \alpha_1$	λ^{UW}
	Negative	λ^{DW}	$\lambda^{UW} + \alpha_2$

If the absolute value of the system imbalance is lower than 140 MW, $\alpha_1 = \alpha_2 = 0$.

If the absolute value of the system imbalance is higher than 140 MW, then:

$$\alpha_1 = \alpha_2 = average\left\{\left(System\ imbalance^{QH-7}\right)^2, \ldots, \left(System\ imbalance^{QH}\right)^2\right\}/15000$$

France

France applies dual pricing as presented in Table D. 3 (based on RTE [188]).

Table D. 3: Imbalance pricing applied in France as of 1 January 2014

		Net Regulation Volume		
		Net Downward Regulation	Zero	**Net Upward Regulation**
BRP	Positive	$min\left[\lambda_{av}^{DW} / (1+k) ; \lambda^{DA}\right]$	λ^{DA}	λ^{DA}
imbalance	Negative	λ^{DA}	λ^{DA}	$max\left[\lambda_{av}^{UW} * (1+k) ; \lambda^{DA}\right]$

When balancing bids are activated for another reason than to ensure the power balance (e.g. to solve network congestions), for λ_{av}^{UW} computation, the price applied is the lower between the bid price and the highest price of the upward activated bids used for balancing. For λ_{av}^{DW}, the price applied is the higher between the bid price and the lowest price of the downward activated bids used for balancing.

From July 1, 2011 the "k" factor is equal to 0.08 [189]. The "k" factor may not be revised more than twice per calendar year and before its application it has to be approved by the French Regulator (CRE).

Germany

Since June 2010, the German TSOs apply single imbalance pricing (reBAP) for the whole country. The imbalance price is based on the average energy costs of FRR and RR. The capacity costs of these reserves are redistributed through the grid tariffs. Imbalance prices are calculated for each 15 minutes. If downward regulation is largely activated, imbalances prices may become negative (meaning that the direction of payment switches).

In December 2012, the Federal Network Agency has introduced modifications in the procedure to compute the imbalance prices (BK6-12-024)[1]. These modifications have resulted in the below steps for calculating the imbalance price (AEP stands for 'imbalance price'):

1. The net income/cost from balancing energy settlement is divided by the net activated balancing energy volume ('saldo NRV') (AEP1). In this computation, the activated balancing energy volume has a negative sign for downward regulation and a positive sign for upward regulation. When AEP1 is positive, BRP with negative imbalance pays the TSO, whereas the TSO pays BRPs with positive imbalances. The opposite occurs with negative AEP1.

2. In case the imbalance price, as calculated by step 1, is higher than the highest energy price of all activated bids, the imbalance price is set to that energy price. A similar procedure is carried out in case that the calculated imbalance

[1] Available at www.regelleistung.net/ip/action/static/chargesys

price is lower than the lowest energy price of all activated bids. This way, the imbalance prices become less extreme (AEP2).

3. AEP2 is compared with the average volume-weighted intraday price. If the NRV-saldo is negative (i.e. there is a system surplus) the intraday price forms the upper limit, and vice versa (AEP3).

4. Additive or subtractive component: If more than 80% of contracted up or down regulating capacity (FRR plus RR) has been activated during an STU, a component is added/subtracted. If more than 80% of contracted up-regulation capacity was activated, the imbalance price becomes AEP3 plus the maximum of 100 €/MWh and 0.5 * AEP3 (whichever is higher is added to AEP3). For downward AEP3 minus the maximum of 100 €/MWh and 0.5 * AEP3.

5. The remaining difference between the costs and the income from the imbalance settlement described in the previous steps is allocated through network usage charges.

6. Price corrections after the publication of the resulting imbalance prices are introduced as a fixed component in the imbalance prices of next month. However, TSOs limit those corrections to a maximum of 3% of the occurred regulating energy costs in this month. In addition, the increase or decrease of the reBAP is limited to 3 €/MWh.

Great Britain

In 2001, the New Electricity Trading Arrangements (NETA) introduced the current trading arrangements in Great Britain, which are based on bilateral trading and a residual balancer (the SO). Under these arrangements, market participant are exposed to "cash-out" (imbalance) prices [102]. The "cash-out" (dual pricing) includes the following prices: System Buy Price (SBP), the price that BRP pays for negative imbalances and System Sell Price (SSP), the price that BRP receives for positive imbalance. In addition, imbalance prices also depend whether the BRP has an imbalance in the same direction of the system (main price) or in the opposite direction to the system (reverse price), the latter correspond to a "Market Index Price".

Table D. 4: Imbalance pricing applied in Great Britain before changes approved in May, 2014

		System imbalance	
		Positive	**Negative**
BRP imbalance	Positive	λ_{av}^{DW} (Main price)	λ^{DA} (Reverse price)
	Negative	λ^{DA} (Reverse price)	λ_{av}^{UW} (Main price)

Source: [104]

The main characteristics of this pricing mechanism are:

- Reverse Price or "Market Index Price" based on selected trades undertaken on the power exchanges functioning in Great Britain (APX and N2EX).
- The main cash-out price is calculated as the average of most expensive 500 MWh balancing actions taking by the SO.
- The costs of involuntary demand disconnections (blackouts) and voltage control (brownouts) are not included in the cash-out calculation.
- Separate trading accounts for consumption and production (production imbalances cannot be net with consumption imbalances).

On May 2014, the Ofgem approved the Electricity Balancing Significant Code Review [104], which will change the existing cash-out mechanism to:

- A single cash-out price for each settlement period (single pricing). The reverse price will be set equal to the main price rather than the Market Index Price.
- Cash-out prices marginal. By calculating these prices using the most expensive action the SO takes to balance the system. This will be done in steps starting with a reduction to 250 MWh by early winter 2014/15 followed by a reduction to 50 MWh by early winter 2015/16 and finally to 1 MWh by early winter 2018/19.
- Inclusion cost for disconnections based on the Value of Lost Load (VLL). It will be introduced in two steps, starting with administrative level of £3,000/MWh by early winter 2015/16 and increasing it to £6,000/MWh by early winter 2018/19 (those values for VLL may be modified by Ofgem, depending among other aspects, whether the capacity mechanism is in place).
- Improvements on the way reserve costs are priced by reflecting the value reserve provides to consumers at times of system stress, by using the Loss of Load Probability (LOLP) and the Value of Lost Load.

Netherlands

The imbalance pricing mechanism in the Netherlands can be categorized mainly as single pricing. However, different imbalance prices are applied for short and long positions. In the Netherlands, imbalance prices are based on the marginal prices of activated reserves. However, imbalance price also depends on the regulation state [190]: 0 (no regulation), +1 (upward regulation), -1 (downward regulation) and 2 (two-sided regulation). Furthermore, an incentive component (additional penalty) is added to the imbalance prices in periods of high system imbalances. This incentive is rarely activated, in total 10 weeks between 2010 until 2012, and with relative small values: for 7 weeks its value was 1 €$/MWh$, for two weeks 3 €$/MWh$ and

5 €/MWh for a week. The energy imbalances and imbalance prices are computed every 15 minutes.

Table D. 5: Imbalance pricing applied in the Netherlands

		Regulation States			
		-1 (downward)	0 (no regulation)	**+1 (upward)**	2 (two-sided)
BRP imbalance	Positive	$\lambda^{DW} - ic$	$\lambda^{mid} - ic$	$\lambda^{UW} - ic$	$\lambda^{DW} - ic$
	Negative	$\lambda^{DW} + ic$	$\lambda^{mid} - ic$	$\lambda^{UW} + ic$	$\lambda^{UW} + ic$

Where: ic is an incentive component and λ^{mid} is the midpoint between the lowest bid price at the upward and the highest bid price at the downward regulating side.

Source: [190]

Nordic Region

The Nordic region has common rules for imbalance settlement, which set imbalance prices differently for consumption and production [191]. For consumption, single pricing is applied, while, for production, dual pricing is used. The Danish imbalance pricing for production units is represented in Table D. 6. For production imbalances, if a BRP has an imbalance in the same direction of the system, the imbalance price corresponds to marginal energy price of activated balancing energy. On the other hand, if the BRP has an imbalance in opposite direction to the system, the DA price is applied as the imbalance price. In case of no activation of reserves, individual imbalances are set at the DA price. The imbalance prices are computed hourly, while imbalances are computed on a quarter-hourly basis.

Table D. 6: Imbalance pricing applied in Nordic Region for generation units

		System imbalance		
		Positive	Zero	**Negative**
BRP imbalance	Positive	λ^{DW}	λ^{DA}	λ^{DA}
	Negative	λ^{DA}	λ^{DA}	λ^{UW}

Spain

The imbalance prices in Spain are defined in REE [133] and computed according to Table D. 7. The imbalance prices are computed hourly.

Table D. 7: Imbalance pricing applied in Spain

		System Imbalance		
		Positive	Zero	**Negative**
BRP imbalance	**Positive**	$min\left(\lambda^{DA};\lambda_{av}^{DW}\right)$	λ^{DA}	λ^{DA}
	Negative	λ^{DA}	λ^{DA}	$max\left(\lambda^{DA};\lambda_{av}^{UW}\right)$

In the Spanish case, λ_{av}^{DW} and λ_{av}^{UW} are the volume weighted average price of downward and upward (respectively) activated balancing energy bids from the deviation management, FRR and RR markets.

Summary

European electricity short-term market designs under high penetration of wind power

In the liberalized context of today's European electricity systems, electricity supply and demand are situated in competitive markets. Since the opening up of the system to competition, the balancing function has largely been redesigned to be accommodated by short-term markets. Additionally, the European Union (EU) has adopted ambitious targets for decarbonization of the electricity sector. Renewable energy sources for electricity (RES-E), especially wind and solar power, will play an important role in achieving the new policy targets. In a RES-E dominated electricity system of the future, variability and unpredictability of intermittent RES-E will be prominent features that require constant attention over a range of time frames, from day-ahead to real-time. Technically, generation and demand should be able to respond to changes in natural resources availability (wind and solar). Institutionally, the electricity market mechanisms also need to be adapted to systems with higher variability and limited predictability of generation.

The main focus of this thesis is on the accommodation of wind power in the short-term electricity markets. In some European countries, wind energy is already supplying more than 20% of total electricity demand, and in some instances even more than 50%. This thesis analyzes the economic efficiency as a function of current market designs for short-term electricity markets in Europe, with the aim to improve their economic efficiency.

This research aims to answer the following research question:

Given the increasing share of wind power in the European electricity system, to what extent can the short-term electricity market designs improve economic efficiency without endangering the system security?

European intraday market designs

Intraday markets enable intermittent RES-E based power producers to trade updated energy forecasts close to delivery time. Currently two types of intraday market are found in Europe: discrete auctions and continuous trading. The Iberian and Italian markets rely on discrete auctions, while the rest of the EU countries opted for continuous trading. These two market designs differ considerably in terms of how the price is determined; how many time-specific energy products can be traded closer to real-time and how cross-border transmission capacity is priced, among other important design variables.

Most countries intraday markets currently present low trading volumes. An exception is the Spanish intraday market. But this is because a favorable combination of specific market rules (such as the dual imbalance pricing mechanism, the allocation of balance responsibility to all market parties, and unit scheduling instead of portfolio balancing) that encourage the market parties to participate in the Spanish intraday market. Moreover, the interaction between the Spanish intraday market and other market mechanisms (such as the different balancing markets and congestion management), led to the emergence of arbitraging opportunities, especially for intermittent RES-E. These arbitraging opportunities, which are also strongly related to the design of RES-E support schemes, impose additional costs on consumers, as they affect the computation of reserve requirements made by the System Operator.

The German intraday market design, similar to other Northwest European countries, is based on continuous trading. This design significantly differs from the day-ahead market or the discrete auctions. Based on 2011 data for the German market, the behavior of the German intraday market differs substantially from the Spanish market (with higher trading volumes close to the gate closure time). The analysis of the German market yields valuable insights for bidding strategies that include the intraday trading opportunities. In addition, for the German case, changes in the support schemes for intermittent RES-E show changes in the use of balancing services by the System Operator.

Continuous intraday trading has been chosen for European wide implementation. However, important aspects, such as the cross-border transmission capacity pricing mechanism, so far remain undefined in the final design, even though this will increase in relevance in the context of increasing cross-border flows.

This thesis proposes the introduction of "convergence bidding" to increase liquidity in the European intraday markets, which would allow financial arbitraging between the day-ahead and the intraday markets, without compromising the system reliability. Convergence bidding has been implemented in USA markets with satisfactory results in terms of economic efficiency and flexibility options. The analysis performed in this thesis for the Spanish and German markets, based on market prices, shows that implementation of convergence bidding holds potential for positive impacts on market efficiency and market integration of intermittent RES-E.

Specific balancing rules for wind power

Different balancing rules are applied to wind power in different countries, with respect to, for instance, the extent to which wind power producers are responsible for energy imbalances and how imbalances are priced. This thesis evaluates their effects on wind power producers' bidding strategies. To do so, a quantitative analysis is presented for an offshore wind farm, considering differences in prices and balancing rules in Belgium, Denmark, Germany and the Netherlands. The quantitative approach uses a stochastic optimization model that maximizes the profits of a wind power producer by trading in the day-ahead and intraday markets and decides the final energy delivered. The results show that the imbalance pricing design and the allocation of balance responsibility significantly affect wind power producers' revenues (from around 10% to 30% of the income in comparison with bidding the forecasted energy in the markets). The analysis also shows that wind power producers deviate differently, in different countries – under different balancing rules, from the energy forecasts in their bidding behavior. The balancing rules should be considered in interaction with other market regulations, such as the design of RES-E support schemes, as they can significantly impact the revenues of wind power producers.

Furthermore, this thesis examined the benefits of cross-border intraday markets. In this analysis, the cross-border intraday available capacity between the Netherlands and Germany is considered, and different forecasting time frames are tested. The benefits from trading in the intraday market appear to be approximately 5% of the total income. The results stress the importance of intraday market integration in Europe, which may contribute to the cross-border balancing of wind power and improve the liquidity of national intraday markets.

Wind power contributing to system balancing

The participation of wind power in the provision of balancing services can substantially contribute to improve the flexibility of the system, especially in case of high generation and low demand, or when quick energy changes are required to balance the system. This provision of balancing services can be economically more efficient than any alternative option. In addition, the participation of wind power in balancing mechanisms enables the possibility for these units to reveal updated energy forecast through the market. This thesis highlights that under certain circumstances, such as local balancing problems, wind generators can bid high negative prices in order to reduce their generation. In such cases, wind power producers potentially earn more than what they receive by feeding all energy into the grid. Price caps based on the prevailing support schemes are recommended policy to avoid windfall profits for wind power producers.

Impact of network congestions in the design of balancing mechanisms

In electricity markets, the grid deeply impacts the market designs. One example that illustrates the effect of the interplay between the grid and the balancing mechanisms is the imbalance pricing applied in the German market. Germany applies a single imbalance pricing for the whole country, while network congestions are increasing within the country, creating adverse imbalance price signals.

Alternative designs for imbalance pricing can improve price signals even in the situation of network congestion. Nodal pricing is a robust approach to deal with grid congestions and energy imbalances. However, nodal pricing requires a significant change in the European market designs and, given the political sensitivity of nodal pricing, it is not likely to be implemented soon. As an alternative, a mix of dual and single pricing can be implemented to reduce adverse price signals.

Alternatives for the priority dispatch rule for renewable energy sources

This thesis evaluates a market-based approach to deal with RES-E curtailment for the Spanish 2020 scenario by using a system operation model. With this model the impact of changes in the current market rules on economic efficiency are examined, as well as redistributional effects among market parties. The model results show that, by removing the priority dispatch and allowing negative prices, the costs for consumers are reduced (by 1.56%) while the revenues of intermittent RES-E generators are hardly affected in comparison with the current situation. In addition, the proposed changes would yield better short-term price signals of inflexibility of the system, as the zero price floor distorts short-term price signals.

Future renewable installations are expected to receive lower levels of support than existing ones because of technological improvements and, with negative prices in place, they are likely to face more curtailment for which they may require compensation. Such compensation should give locational signals. If curtailment compensation is not provided, additional revenue from support schemes may be required to guarantee adequate returns on investments.

Need for harmonization of European balancing mechanisms

The integration of national markets into a truly European Internal Electricity Market is far from being completed. Currently, the design of balancing mechanisms still varies significantly between European countries. Furthermore, cross-border short-term electricity trade already occurs due to price differences (day-ahead, intraday, balancing, imbalances). However, as these price differences can partly be attributed to differences in the design and organization of the balancing mechanisms in different countries, guarantees for efficient cross-border electricity trade are inadequate.

European institutions are currently designing general guidelines for the development of national network codes which, however, still leave freedom for national authorities to design, in some aspects, their own national regulations within the network code boundaries. The resulting heterogeneity in designs may cause economic efficiency losses in cross-border electricity trade.

An agent-based model, presented in this thesis, shows how companies with generating units in two neighboring countries can benefit from different imbalance pricing mechanisms. A difference in pricing mechanisms increases the costs for one of the System Operators and decreases the balancing costs for the other one, with higher costs for consumers in the first country. With a scenario of 50% wind capacity installed, these effects significantly increase. The agent-based modeling results show that harmonization of imbalance pricing mechanisms reduces the arbitrage opportunities for multinational companies and therewith the net-transfer of revenues between System Operators.

Conclusions

This thesis provides an analysis of current and future challenges for the adaptation of short-term European electricity market mechanisms to accommodate a higher penetration of intermittent RES-E. In this context, the Internal Energy Market in Europe should ideally be fostered by a harmonized set of market rules for all the countries that are part of it. In this respect, European institutions may be more ambitious in defining such a single set of rules in the Network Codes instead of proposing minimum requirements that give significant freedom for different national designs. With this latter approach, and because of cross-border electricity trade, there is a real and imminent risk that the current situation of heterogeneity in market designs persists, with a negative impact on both economic efficiency and system security.

One stressed argument in this thesis is the intricate interaction between the various short-term market mechanisms, which influences their efficiency. For example, congestion management and balancing mechanisms are strongly interrelated. Network congestions limit the possibility to use balancing resources from any part of the grid; therefore, the cost of balancing services depends on the grid location. As European electricity prices are usually set at the national level, adverse price signals can emerge in the absence of locational price signals. Therefore, with the current changes towards more intermittent RES-E in the European generation mix, locational price signals become more relevant.

In order to achieve a robust design and well-functioning of the short-term market mechanisms, these mechanisms should be based on competitive market forces, with as little administrative interference and distorted price signals as possible. This thesis provides various examples of current regulations in European countries that generate distortions in the short-term market mechanisms. For example, differences in the allocation of financial responsibility to wind power producers with respect to energy imbalances give different incentives to these market parties to deviate in their bids from the energy forecasts. In addition, the elimination of price caps and floors in systems with high intermittency is required to better manage the intermittency in current and future electricity systems. Furthermore, market regulations such as the priority dispatch rule for renewable sources give rise to operational decisions that are not economically efficient, at least in the short-term. However, the modification of this rule implies additional design choices, for instance to what extent market parties should receive compensation in case of generation curtailment.

A weak point of the European balancing mechanisms encountered in the development this thesis is a lack of transparency at different levels, mainly in the disclosure of balancing costs and the timely publication of balancing data. This limits the possibility for investment in flexibility and for market parties to react to the costs associated with imbalances. Furthermore, the publication of relevant data would allow a detailed analysis of the systems performance, and actions taken by relevant market parties such as the System Operators.

A relevant finding of this thesis is that, depending on the market design, RES-E generators will not necessarily bid the expected energy output in the markets. This is challenging for balancing decisions taken by the system operators close to real time. Furthermore, if additional market distortions exist, market parties (including intermittent RES-E producers) can react to the price signals, with negative effects for the system. This is shown in this thesis with bidding strategies' modeling in Northern European countries and also supported by data from bids in the Spanish and German markets.

List of Publications

Peer-reviewed journal papers

- Chaves-Avila, J.P.; Ramos, A.; Hakvoort, R. Short-term strategies for Dutch wind power producers to reduce imbalance costs (2013). Energy Policy. vol. 52, pp. 573-582.
- Chaves-Avila, J.P.; van der Veen, R.A.C.; Hakvoort, R.The interplay between imbalance pricing mechanisms and network congestions - analysis of the German electricity market (2014). Utilities Policy. vol 28, pp. 52-61.
- Chaves-Avila, J.P.; Ramos, A.; Hakvoort, R. The impact of European balancing rules on wind power economics and on short-term bidding strategies (2014). Energy Policy. vol. 68, pp.383–39
- Chaves-Avila, J.P.; Fernandes, C. The Spanish intraday market design: a successful solution to balance renewable generation? (2014). Renewable Energy Journal (aceepted for publication).
- Koliou, E.; Eid, C.; Chaves-Ávila, J.P.; Hakvoort, R.A. Demand response in liberalized electricity markets: Analysis of aggregated load participation in the German balancing mechanism (2014). Energy. vol 71. pp. 245-254.

Conference paper

- Chaves-Avila, J.P.; Hakvoort, R. Participation of wind power in the European balancing mechanisms (2013). International Conference on the European Energy Market.

Papers under review

- Chaves-Avila, J.P.; Peres, Y.; Lumbreras, S.; Hakvoort, R. Convergence Bidding in Europe: an option to increase liquidity in the intraday markets, improve economic efficiency and renewable sources balancing (2014). Energy Economics (under review).

- Chaves-Avila, J.P.; Bañez-Chicharro, F.; Dietrich, K.; Ramos A. market based approach to deal with curtailment of intermittent energy sources: the Spanish market case study (2014). International Journal of Electrical Power & Energy Systems (under review).

Curriculum Vitae

José Pablo Chaves Ávila was born on February 18, 1986 in San José (Costa Rica). He finished high school in 2003 at Salesiano Don Bosco (Costa Rica). He obtained his Bachelor's degree in Economics in 2008 from Universidad de Costa Rica (Costa Rica). He completed an Erasmus Mundus Joint Master in Economics and Management of Network Industries. As part of the Master program, he spent one year in Comillas University (Spain) where he obtained a Master in Electric Power Industry (2009) and one year in Paris-Sud University (France) where he obtained a Master in Numerical Economics and Network Industries (2010).

In September 2010 he started a Erasmus Mundus Joint Doctorate in Sustainable Energy Technologies and Strategies (SETS) in Delft University of Technology (the Netherlands), where he spent 18 months. As part of the SETS program, he spent 18 months in Comillas University (Spain) and 6 months in the European University Institute (Italy). During his research José Pablo published four journal papers and additional working papers, presented in international conferences and seminars and collaborated with others researches.

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